European Network of
Transmission System Operators
for Electricity

Mid-term Adequacy Forecast

2016 edition

THIS MID-TERM ADEQUACY FORECAST (MAF) 2016 IS A NEW MID-TERM ASSESSMENT OF PAN-EUROPEAN ADEQUACY. THE MAF REPLACES ENTSO-E'S SCENARIO OUTLOOK AND ADEQUACY FORECAST OR SO&AF. THE MOVE FROM SO&AF TO MAF IS DUE TO A SIGNIFICANT CHANGE IN THE METHODOLOGY USED FOR THE ASSESSMENT. THE MAF 2016 IS ONE OF ENTSO-E'S MANDATES UNDER EU LEGISLATION AND IS PART OF TYNDP 2016 PACKAGE. IT WILL BE OUT FOR PUBLIC CONSULTATION DURING THE SUMMER 2016. A FINAL REPORT AFTER TAKING INTO ACCOUNT STAKEHOLDER' FEEDBACK WILL BE ISSUED DURING AUTUMN 2016.

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1 Introduction to the MAF

What is the 'MAF'?

The Mid-term Adequacy Forecast (MAF) is a Pan-European assessment of the risks to security of supply and the need for flexibility over the next decade. The methodology used by ENTSO-E takes into account transformation of the power system with increasing variable generation from renewable energy sources.

The recommendations of the Electricity Coordination Group (ECG) in 2013 invited ENTSO-E to update their adequacy methodology and assessments to better account for the risks to security of supply and the need for flexibility as the Pan-European power system moves towards higher levels of renewable energy sources (RES). These improved assessments should also help highlighting the contribution of electricity interconnectors to national adequacy at times of potential scarcity.

The methodology used in ENTSO-E's adequacy reports has evolved in response to the ECG recommendations and further stakeholder consultation during 2014. These resulted in the so-called "ENTSO-E Adequacy Target Methodology" and implementation roadmaps[1].

The ECG[2], stated that **adequacy assessments are more useful when focussed on the mid-term horizon** (up to 10 years ahead). These can be used **to assess potential load shedding risks** and send signals to both market players and decision-makers of the need for the generation fleet to evolve. Adequacy assessments are less informative beyond this period due to the increasing levels of uncertainty around the future energy systems. The mid-term adequacy forecast (MAF) fulfils the role of providing a Pan-European adequacy assessment for the next ten years.

Methodology: has ENTSO-E developed something new?

The MAF presents the first Pan-European assessment of generation adequacy using market-based probabilistic modelling techniques. Additionally the MAF's results have been benchmarked using four different calculation software tools.

The MAF presents the first Pan-European probabilistic assessment of adequacy. While market-based probabilistic modelling approaches have already been adopted in some national generation adequacy studies and the PLEF regional adequacy assessment[3], this is the first time such studies have been conducted at the Pan-European level. This represents a significant analytical achievement. Moreover, this has involved extensive collaborative effort of representatives from TSOs covering the whole Pan-European area under the coordination of ENTSO-E.

[1] https://www.entsoe.eu/about-entso-e/system-development/system-adequacy-and-market-modeling/adequacy-methodology/Pages/default.aspx
[2] Report of the European Electricity Coordination Group on The Need and Importance of Generation Adequacy Assessments in the European Union, Ref. Ares(2013)3382105 - 30/10/2013
[3] http://www.benelux.int/files/4914/2554/1545/Penta_generation_adequacy_assessment_REPORT.pdf

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The MAF 2016 represents an important milestone in the development of probabilistic market-based modelling for adequacy assessments and there are a number of achievements worth highlighting. These include:

1. The study involves the whole Pan-European perimeter including Turkey

Figure 1 - Pan-European perimeter covered by the MAF – countries in blue (*This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence.*)

2. The results have been benchmarked by calibration of four different analytical tools, which also account for the regional differences in power systems across Europe. This increases the consistency and robustness of the complex analytical results presented in the report, and helps to improve the links between the MAF and regional/national adequacy studies.

3. Also noteworthy are a number of important technical developments that meant it was possible to adapt the analysis to the specific requirements of different regions within Europe. These include:
    a. an advanced temperature-sensitive load model.
    b. harmonised probabilistic hydrological analysis with data sets for extended dry and wet hydro conditions.
    c. forced outage rates (FOR) for thermal units as well as on HVDC links.

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Which is exactly the scope of MAF and how does it link with regional/national adequacy assessments?

The MAF aims to identify and assess the risks to generation adequacy on a Pan-European level. It should be regarded as providing a boundary regarding data and assumptions for further studies at regional level and national level.

The main scope of this report is to identify and assess the risks to generation adequacy on a Pan-European level. The report is updated annually so that the assessments are carried out using the best available information (for example demand projections, available generation capacity, commissioning and de-commissioning of system's assets and infrastructure elements, etc..). Moreover, an annual assessment is designed to provide consistent Pan-European boundaries that help defining a framework (for instance data/results) for further studies at regional level and national level.

Regional and national studies allow greater focus on sensitivities and potential solutions that are most relevant to the areas concerned. Pan-European assessments help to ensure the necessary consistency between the different regional/national assessments and any of the proposed solutions within those.

The application of consistent methodologies at national, regional and European level is necessary to allow a realistic assessment of available cross-border support considering many different scenarios. The methodology should therefore be common between these three levels, but taking into account national specificities. However, the decision to implement measures to ensure security of supply at national level remains directly linked to the responsibility for security of supply.

ENTSO-E has developed consistent bottom-up scenarios for the future European power systems in 2020[4] and 2025. The scenarios are designed to assess adequacy, based on key metrics such as energy not-served (ENS) and loss of load expectation (LOLE), and considering the role of interconnection as well as cross-border exchanges. The analysis has been carried out on data that has been collected from all TSOs within the Pan-European perimeter based on principles set out by ENTSO-E.

All tools used in these study are used by TSOs for national, regional and Pan-European studies. All tools have been tested to ensure that they are able to match the basic methodology requirements of performing probabilistic market modelling adequacy assessments. TSOs have expertise in using these tools and are able to capture the important features of their national or regional perimeter for the Pan-European simulations. Comparison of results between tools ensures quality and robustness of the inputs as well as of the results. Also this exercise ensures the consistent link between Pan-European studies performed here and possible subsequent regional or national studies by TSO.

Pan-European studies will contribute to the debate and trigger discussions and actions if one/several countries present adequacy issues. Those countries could build on the analysis here performed and use the same methodology to check and consider solutions both locally and/or within a regionally coordinated framework. Regional and national studies will also benefit from increased quality of data in neighbouring countries, from the Pan-European framework developed here. The Pan-European, regional and national levels can complement each other by use of a common methodology, data and assumptions.

[4] The 2020 scenario considered here is fully consistent with the Expected Progress 2020 scenario of TYNDP 2016.

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What are the lessons learnt?

1) Use of sophisticated modelling tools requires a huge effort but provides a significant added value to increase the quality and robustness of the results

2) The simulations are computationally demanding and require a permanent group of TSO modelling experts to improve the methodology, align assumptions, achieve robust results and spread knowledge at the same time

3) Coordination is needed between ENTSO-E's Pan-European assessment and national studies

Each step towards increasing the level of details of the data and representation used in the models **significantly increases the complexity** of the mathematical problem to be solved. The complex probabilistic simulations performed in MAF 2016 for the whole Pan-European perimeter have resulted in computationally demanding simulations. The modelling tools' computational capabilities have been tested and pushed by TSOs in this study. For instance each simulation run of the '*Base Case*' simulations took over several days for all tools available. This should be taken into account in order to understand the effort needed for calibrating the models.

There is an opportunity to work closer with the TSO's to better understand their timelines for producing national adequacy reports, and where possible, seek greater harmonisation with the timelines of the annual MAF publication. This will help improve the consistency of data, analysis and key messages between the national reports and the MAF, which will help stakeholders to realise the benefits from all studies.

What are the limitations of the current methodology? What are the next steps?

A market model always presents a simplified representation of the real behaviour of the power system. The results obtained in this report should **always** be understood under the following assumptions and limitations of the current implementation of ENTSO-E methodology.

- Use of 14 years (2000-2013) climatic years within ENTSO-E Pan-European Climate Database.
- Market models use actual Bidding-Zones (BZ) configurations and the modelling of each market zones consider them as congestion free zones or '*copper plate*' zones.
- No explicit modelling of intraday trading or balancing market is performed. In order to make this simplification more sensible for adequacy studies, sensitivity runs including and excluding the contribution of operational reserves have been considered.
- Transmission capacities between BZs are considered as constant across the year. Power exchange limits do vary in reality and are dependent on maintenance schedules and unexpected unavailability of system's elements. In order to make this simplification more sensible for adequacy studies, conservative assumptions have been considered. Also sensitivity runs assuming 'forced outages' for selected HVDCs have been considered.
- No explicit modelling of DSM/DSR has been performed in this report. Potential for load reduction capabilities has been however collected from TSOs. Although for some TSOs, these figures do present a view on market based demand side response, meaning that if prices are getting high, some

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consumers will not consume, in general the figures collected present last resort emergency capabilities available to TSOs, rather than estimates for a future market for DSM. Due to the heterogeneity of the available data, these figures have been used only in relation to the discussion of the results.
- No flow-based market coupling has been modelled in this report. The exchanges obtained in this report should therefore be understood as ‘commercial flows’ and not as ‘physical flows’. In order to make this assumption more sensible for adequacy studies, simultaneous importable/exportable capacities have been imposed, which prevent the modelling of non-realistic commercial flows.
- The scenarios analysed in MAF 2016 for 2020 and 2025 are based on a best estimate of the evolution of the generation mix (thermal and renewable park) and transmission capacity as well as demand forecast of each country. These scenarios are referred as Scenario B “Best Estimate/Expected Progress”. For 2020 this scenario is common to the TYNDP2016 2020 scenario. Within the principles set out by ENTSO-E for a common and consistent data collection, all TSOs have provided data considering to their best knowledge the evolution of their generation mix, in some cases including “economic viability” of the scenarios provided. No further sensitivity has been performed regarding “economic viability” of the data provided by TSOs and instead the focus has been on the identification of Pan-European adequacy risks for those scenarios.

There is a need for continued development of both the modelling tools and the underlying data assumptions within ENTSO-E MAF reports. Further developments are envisaged for future MAF reports:

- Extension of the Pan-European Climatic Database (PECD) to 35 climatic years.
- Revision of cross-border interconnector assumptions to account for seasonality and operational constrains.
- Revision of thermal portfolio categories and data details and assumptions therein.
- A European overview on anticipated decommissioning of power plants is needed to improve the quality of the data and accuracy of the adequacy assessments performed by ENTSO-E. ENTSO-E welcomes interaction with relevant stakeholders to further improve the availability of data regarding decommissioning/mothballing of plans and considerations of so-called “system-relevant” assets.
- Modelling of demand-side management and demand-side response.
- Use of flow-based market methods.

How should the results be interpreted?

The results cannot be separated from the hypotheses. *“Make it as simple as possible, but not any simpler”* (Albert Einstein)

It must be noted that the conclusions in this report cannot be separated from the hypotheses described and can only be read in reference to these. The hypotheses were gathered by the TSOs according to their best knowledge at the time of the data collection and validated by ENTSO-E’s relevant committees.

ENTSO-E and the participating TSOs have followed accepted industry practice in the collection and analysis of data available. While all reasonable care has been taken in the preparation of this data, ENTSO-E and the TSOs are not responsible for any loss that may be attributed to the use of this information. Prior to taking business decisions, interested parties are advised to seek separate and independent opinion in relation to the matters covered by this report and should not rely solely upon data and information contained herein. Information in this document does not amount to a recommendation in respect of any possible investment. This document does not intend to contain all the information that a prospective investor or market participant may need.

ENTSO-E emphasises that ENTSO-E and the TSOs involved in this study are not responsible in case the hypotheses taken in this report or the estimations based on these hypotheses are not realised in the future.

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2 Our main findings - Overview of results (presentation with feedback from TSOs)

How to understand the probabilistic results of this section?

Probabilistic simulations are needed to account for all possible combinations of uncertainties that the power system will face in the future. It is also important that these combinations account not only for the average conditions of the system but, even more importantly, also for the most extreme conditions which typically will push the power system to a stressed situation (e.g. situations of scarcity). With increased shares of variable renewable energy sources in the system, the most critical situations may occur in the future at times other than peaks in demand.

Also seasonality/climate factors should be properly considered in combination, namely: low temperatures leading to high demand in winter (or high temperatures leading to high demand in summer) combined with dry years, low precipitation, leading to scarcity of water in hydro reservoir, etc. Probabilistic methods use climate databases to assess the variability of RES (renewable energy sources) production as well as the seasonality of demand, hydro production and thermal production availability. A simulation of a given hour of the interconnected Pan-European power system is performed by *combining* Load × RES × Hydro × Thermal × Cross border capacity factors.

The example below shows two such possibilities:

- The first hour presents an example of a potentially critical situation regarding generation adequacy.
- The last hour considered is a rather moderate situation in which no generation adequacy problems are expected.

HOUR	LOAD	RES	HYDRO	THERMAL	CROSS BORDER CAPACITY	
Scenario 2020 Hour 1	Low /High Temp High Demand (Winter/Summer)	Low Wind Low PV	Dry conditions Low hydro production	Low availability of Thermal generation	Low cross border capacity	⚠
...	...	...	...	...	...	
Scenario 2025 Hour 8760	Moderate Temp Moderate Demand	High Wind High PV	Wet conditions	Normal availability of Thermal generation	Normal cross border capacity	✓

For each future scenario of installed capacities of the Pan-European power system (2020 and 2025 scenarios) a systematic combination of all uncertainties is performed to setup the hourly simulations of the interconnected Pan-European system. This is the so called *Monte-Carlo* method (see chapter 3 for details).

In this chapter we present the main results of these simulations. A number N of simulation runs for each scenario 2020 or 2025 is performed by considering combinations of: 14 Wind – PV – Temperature climatic year situations × between 3 and 6 hydrological yearly situations depending on the region × 200 ÷ 300 situations for random outages samples of thermal units and HVDC links. For each scenario 2020 or 2025 and **each of the N simulation above**, hourly simulations of the whole interconnected Pan-EU perimeter are performed, resulting into 8760 hours – variables calculated for each simulation run.

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For each hour of these simulations, a value of ENS is calculated. This value can be either:

ENS = 0 (no adequacy problem)

or

ENS ≠ 0 (adequacy problem found)

The number of times a given value of ENS is found is counted and stored. This number divided by the total number of simulations, gives you an idea of the 'probability' of occurrence of this value of ENS. Bookkeeping of the number of counts of ENS allows us to construct the so-called Probability Distribution (PD) function.

The PD function for ENS typically looks like the one in Figure 2. Most of the time the records find that ENS = 0, *i.e.* that the system is adequate. However due to the large number of possibilities considered, different sets of hours with different values of ENS are found. A small number of hours report a very large value of ENS, when the system might face significant scarcity situations.

How to extract the main messages from the wealth of data from the probability distribution?

This is done by computation of the so-called **median – average** and **percentiles** (P50, P95).

- **Average (mean)**: This is the average value of ENS found among all the situations
  ENS = Σ ENS / Σ Simulations.

- **Median (P50):** This is the value of ENS for which there are equal number of simulations reporting ENS >P50 than ENS< P50 (ENS > (or <) P50%, 50% of the times). The area covered by the PD on the left and on the right hand side of the P50 value are therefore equal. Note that if the distribution would be symmetric, P50% and Average would coincide. The fact that P50 < ENS, indicates that the PD is not symmetric and the presence of so-called *long tails* of ENS, large values of ENS which can be found with very low but finite probability.

- **"1-in-20 years" (P95):** This is the value of ENS for which 95% of the values found are lower than P95 (ENS < P95% 95% of the times). Only 5% of values found are higher than this value. P95% gives a measure of high values of ENS which are likely to occur with very low but still finite probability of occurrence. P95 gives a measure of the 'low probability – high impact: worst case 1-in-20 years' situation observed.

These 3 values P50, Average and P95 are indicated in the probability distribution example shown in Figure 2 below:

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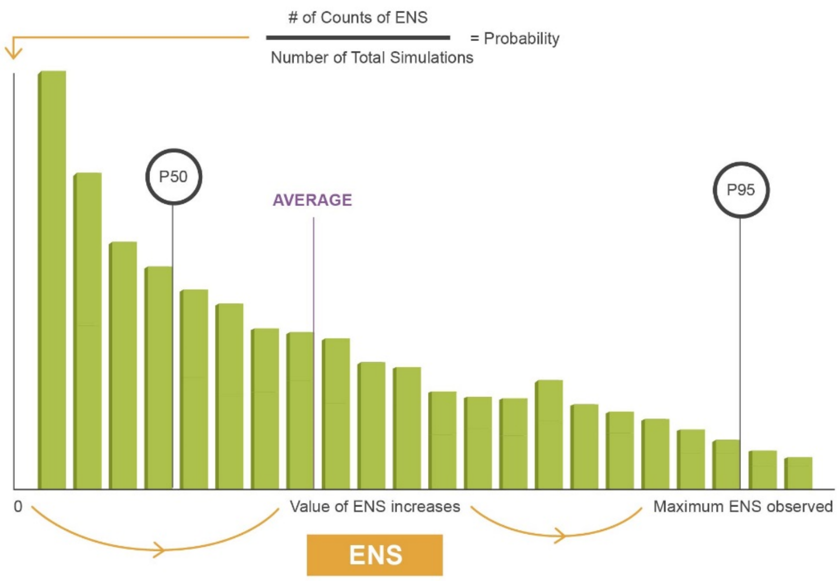

Figure 2 - Probability Distribution function

For each simulation below the P50, Average and P95 values are reported for the countries which indicate adequacy problems.
Furthermore, since the simulations have been performed with several tools, referred as *S (Simulator)*, the results of the different tools are also presented, next to each other.

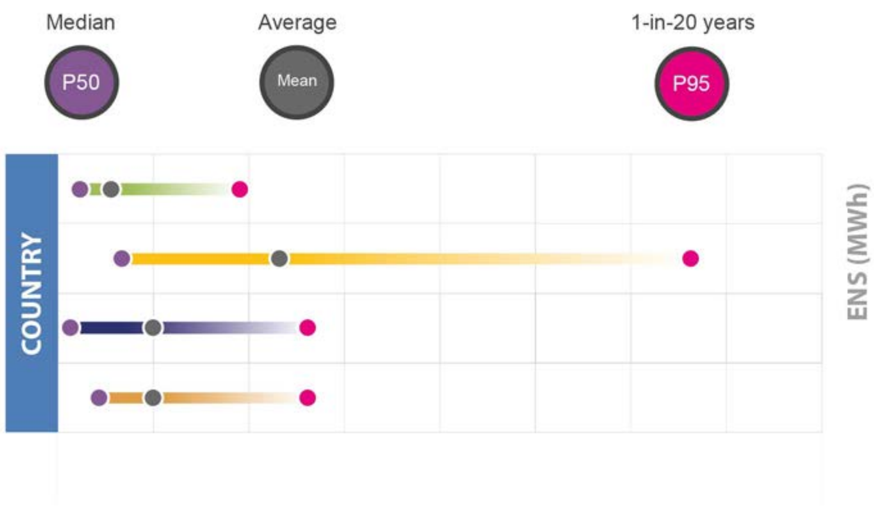

Figure 3 – Explanatory example of presentation of main results (P50, Mean, P95) obtained by the 4 market modelling tools used (denoted by the different color bars).

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General overview of the results (including feedback from TSOs)

Note:
A link to the country comments by each TSO (Appendix 2) can be found in the caption under the 'Overview Table' below. Appendix 2 present the comments by each national TSO on the results obtained in the MAF 2016, in relation to each country's own assessment of adequacy level, its national adequacy standards and the measures taken to maintain these in case of problems.

Three simulations runs have been defined in MAF 2016, namely:

Simulation Runs
Base Case: Day-ahead adequacy. Operational reserves do not contribute to adequacy
Sensitivity Case I: Day-ahead adequacy + operational reserves contributing to adequacy ~ 'real time' adequacy
Sensitivity Case II: Sensitivity Case I + HVDC forced outages

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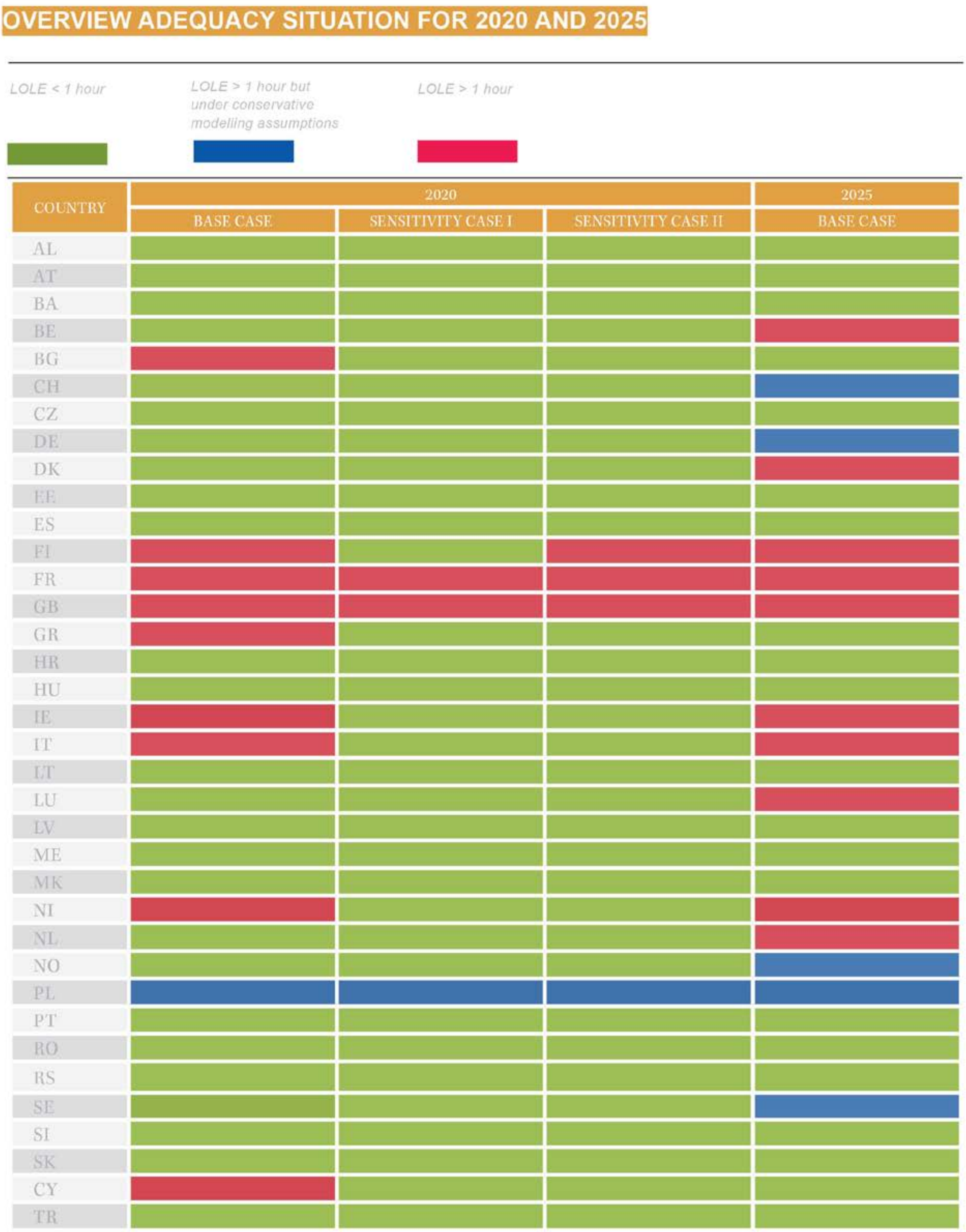

1) National Generation Adequacy view 2020-2015 and its relation to the MAF 2016 results can be found in the Appendix 2:

AL AT BA BE BG CH CZ DE DK EE ES FI FR GB

GR HR HU IE IT LT LU LV ME MK NI NL NO PL

PT RO RS SE SI SK CY TR

Summary Adequacy Indicators (ENS and LOLE) for 2020

The table below provides an overview of the values for Energy Non-Served (ENS) and Loss of Load expectation (LOLE) found for several countries within the Pan-European perimeter and within the different simulations performed for year 2020. See in Appendix 2, the countries' comments on the results obtained in the MAF 2016, with respect to each country's own assessment of adequacy level, its national adequacy standards and the measures taken to maintain these in case of problems.

If a country is not mentioned in the table below, it is because, no adequacy problems are observed for such country and then ENS and LOLE should be understood as being zero/negligible.

Table 2 - Results summary table for year 2020. (S# denotes Simulator # results).

		Base Case				Sensitivity (1)				Sensitivity (2)			
Country	**Sim.**	**ENS (MWh) Average**	**LOLE (h) Average**	**ENS (MWh) Average (all)**	**LOLE (h) Average (all)**	**ENS (MWh) Average**	**LOLE (h) Average**	**ENS (MWh) Average (all)**	**LOLE Average (all)**	**ENS (MWh) Average**	**LOLE (h) Average**	**ENS (MWh) Average (all)**	**LOLEAverage (all tools)**
GB	S2	14247	7.8	12090	**7.6**	7834	4.5	7082	**4.4**	--	--	8501	**5.4**
	S4	5440	3.6			4877	3.2			5534	3.6		
	S5	13612	7.5			7877	4.4			9927	5.6		
	S6	15061	11.5			7742	5.4			10043	7.0		
FR	S2	3332	2.3	3418	**2.6**	303	0.3	1059	**0.8**	--	--	1176	0.8
	S4	4439	2.9			3251	2.2			3293	2.2		
	S5	912	0.7			552	0.4			85	0.1		
	S6	4991	4.7			130	0.1			150	0.2		
FI	S2	1014	3.3	1905	**5.7**	1	0.0	16	0.1	--	--	260	**1.0**
	S4	23	0.1			8	0.1			369	1.3		
	S5	2044	5.9			29	0.1			153	0.6		
	S6	4540	13.6			27	0.1			258	0.9		
IT	S2	94	0.5	951	**2.9**	0	0.0	69	0.2	--	--	94	0.3
	S4	198	0.8			165	0.6			170	0.6		
	S5	589	3.3			2	0.0			2	0.0		
	S6	2922	7.0			109	0.2			111	0.2		
PL	S2	86	0.2	456	**1.1**	0	0.0	101	**0.3**	--	--	182	**0.5**
	S4	0	0.0			0	0.0			0	0.0		
	S5	479	0.7			0	0.0			33	0.1		
	S6	1260	3.4			404	1.1			514	1.3		
GR	S2	448	1.5	386	**1.6**	0	0.0	1	0.0	--	--	2	0.0
	S4	0	0.0			0	0.0			0	0.0		
	S5	16	0.1			0	0.0			0	0.0		
	S6	1081	4.7			5	0.0			5	0.0		
BG	S2	0	0.0	364	**1.4**	0	0.0	26	0.1	--	--	34	0.1
	S4	4	0.0			1	0.0			1	0.0		
	S5	545	1.9			53	0.2			51	0.2		
	S6	905	3.5			49	0.2			50	0.2		
NI	S2	179	1.1	128	**1.2**	17	0.1	13	0.2	--	--	17	0.3
	S4	17	0.6			11	0.4			15	0.5		
	S5	194	1.0			10	0.1			11	0.1		
	S6	123	2.3			15	0.2			25	0.4		
IE	S2	224	1.0	175	**1.1**	22	0.1	25	0.2	--	--	41	0.3
	S4	55	0.6			37	0.4			48	0.5		
	S5	244	1.1			25	0.1			33	0.1		
	S6	179	1.7			15	0.2			43	0.3		
CY	S2	1	0.1	46	**4.2**	0	0.0	7	**4.2**	--	--	9	**5.6**
	S4	0	0.0			0	0.0			0	0.0		
	S5	96	2.2			0	0.0			0	0.0		
	S6	86	14.5			27	16.8			27	16.9		

Scenario 2020: Base Case

Main messages

- These results provide an outlook of the main adequacy problems for a 2020 scenario assuming operational reserves not contributing to adequacy (e.g. operational reserves constrains on top of day-ahead (D-1) market considerations)
- The following countries present average LOLE > 1 h: BG, CY, FI, FR, GB, GR, IE, IT, NI, PL
- **Results for GB**: The simulations show average LOLE and ENS values of ~ 7 – 8 h and ~ 15 GWh, respectively. Great Britain has a reliability standard of 3 hours/year LOLE, which the MAF 2016 results exceed.

  The results for GB are based on data from National Grid's Gone Green scenario published in the 2015 Future Energy Scenarios (FES). The Gone Green scenario assumes a number of new interconnectors will be available from 2020 onwards. The modelling assumptions in the MAF have adopted a conservative approach to new interconnector capacity. This is useful to assess the potential impact of interconnector projects being delayed across Europe. As a result, most of the new interconnectors assumed to be available in National Grid's scenario have been excluded from this analysis. This capacity has not been replaced with anything else and so the modelling assumptions have created a shortfall of capacity. This has led to higher LOLE / ENS values for GB.

  Both National Grid and ENTSOE agree that the conservative interconnector assumptions are sensible for a Pan-European adequacy assessment. However, some factors that are specific to GB have not been fully accounted for in this adequacy assessment. The most important is that GB has a capacity market. This means that, in reality, the capacity shortfall in this analysis won't exist. The capacity market will ensure that GB has sufficient capacity to meet its reliability standard. In the context of this analysis, this means that if new interconnectors are delayed, then alternative forms of capacity will be successful in the capacity market auctions instead. These alternative forms of capacity have not been included in this assessment. Therefore the LOLE / ENS values reported for GB in the MAF should not be interpreted as an indication of potential adequacy problems.
- The MAF 2016 results have to be strictly understood within the assumptions and data used in the respective simulations.

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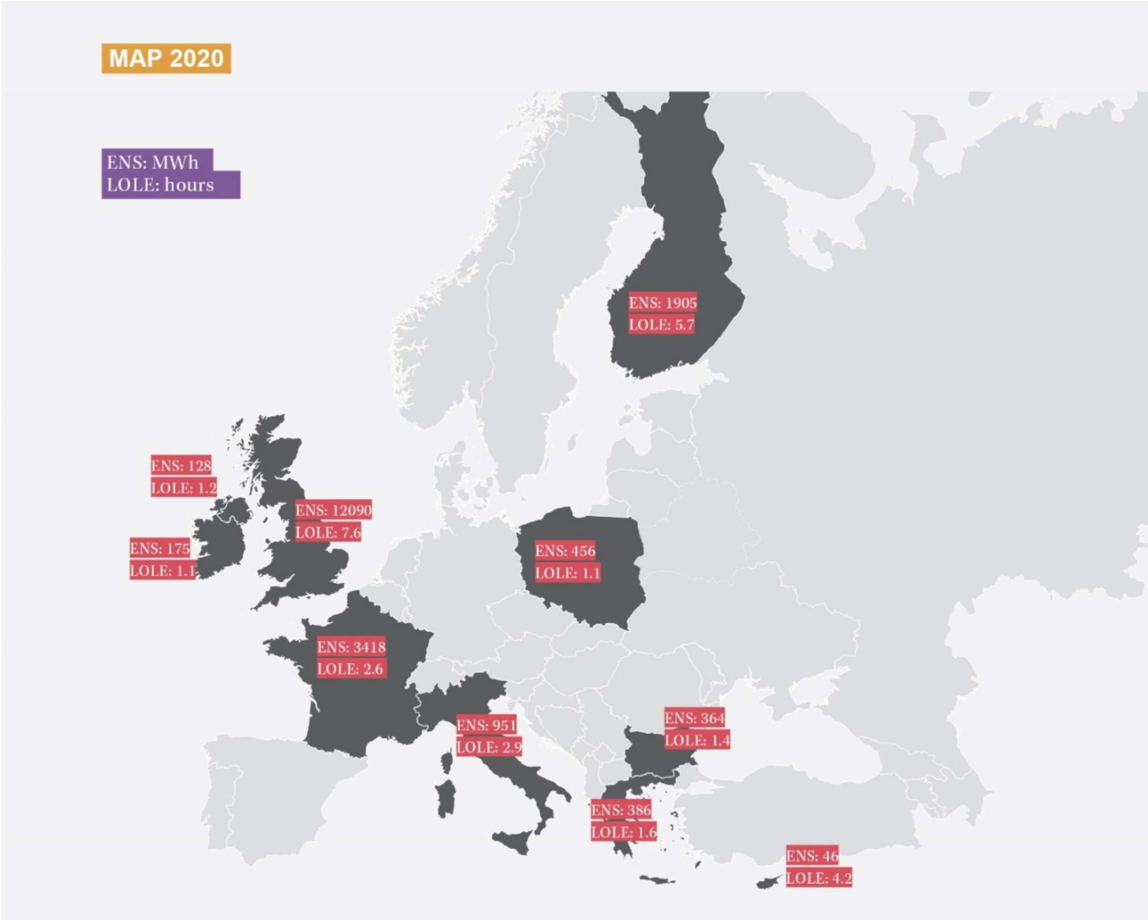

Figure 4 - 2020 Base Case - Map representing countries ENS and LOLE (only for countries with average LOLE > 1 h)

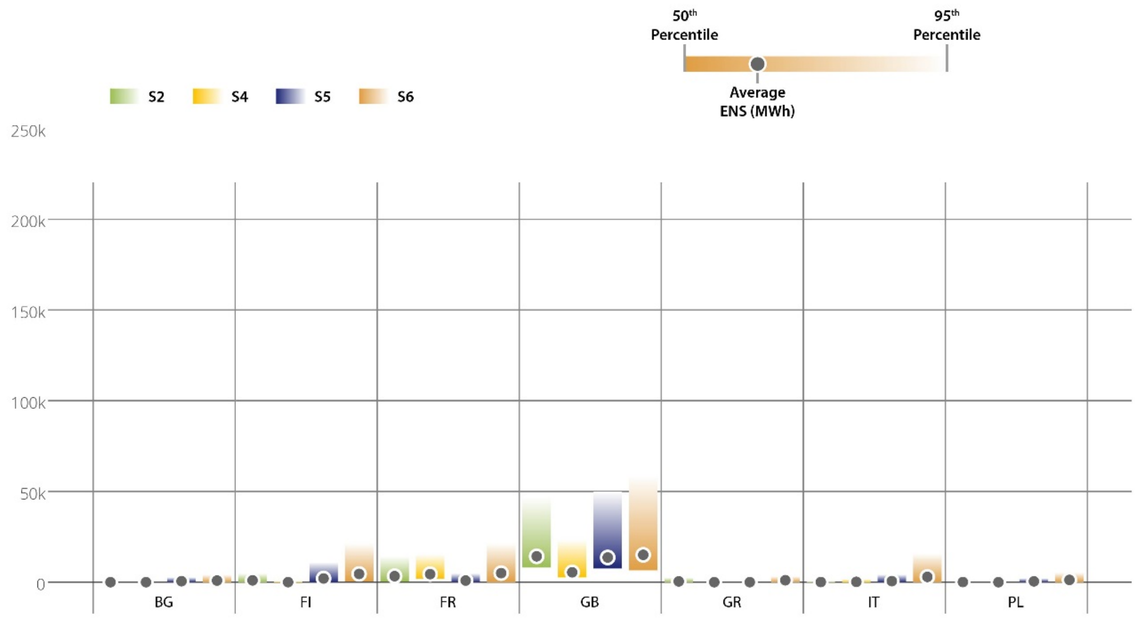

Figure 5 - ENS 2020 Base Case: P50, Average, P95 percentiles. (only for countries from previous map with ENS > 300 MW)

2020: Sensitivity Case I

Main messages

- These results provide an outlook of the main adequacy problems for a 2020 scenario assuming operational reserves contributing to adequacy on top of day-ahead (D-1) considerations.
- The following countries present a LOLE > 1 h: CY and GB.
- **Results for GB**: We refer to the explanations provided above. The reported LOLE / ENS values for GB in the MAF should not be interpreted as an indication of potential adequacy problems. The GB capacity market will ensure that sufficient capacity is available to meet its reliability standard.
- The contribution of operational reserves improves the adequacy situation with respect to the results provided in the Base Case. Only GB, FR and PL still present some minor adequacy problems.
- The results contained in this report should be understood strictly within the assumptions and data used in this chapter.

Figure 6 - 2020 Sensitivity I - Map representing countries ENS and LOLE (only for countries with average LOLE > 1 h)

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2020: Sensitivity Case II

Main messages

- These results provide an outlook of the main adequacy problems for a 2020 scenario assuming operational reserves contribution to adequacy but considering the unavailability of cross-border capacity due to forced outages of selected HVDC interconnectors
- The following countries present an average LOLE ≥ 1 h, GB, FI, CY
- The contribution of operational reserves shows an improvement of the adequacy situation close to 'real-time' with respect to the results provided in the Base Case. Unavailability of HVDC links increases ENS and LOLE for some countries. FR and PL still present some minor adequacy problems
- **Results for GB**: We refer to the explanations provided above for GB. Unsurprisingly, we also observe significant sensitivity of the main adequacy indicators ENS/LOLE to that availability of interconnectors from GB to IE and continental Europe. However, such events are considered as part of the national analysis for the GB capacity market to ensure that sufficient capacity is available to meet its reliability standard
- **Results for FI**: Finland relies on imports from its neighbours in scarcity situations. Unavailability of cross-border capacity of HVDC connections between FI and SE, and FI and EE, translates into adequacy problems.
- The results contained in this report should be understood strictly within the assumptions and data used in this chapter.

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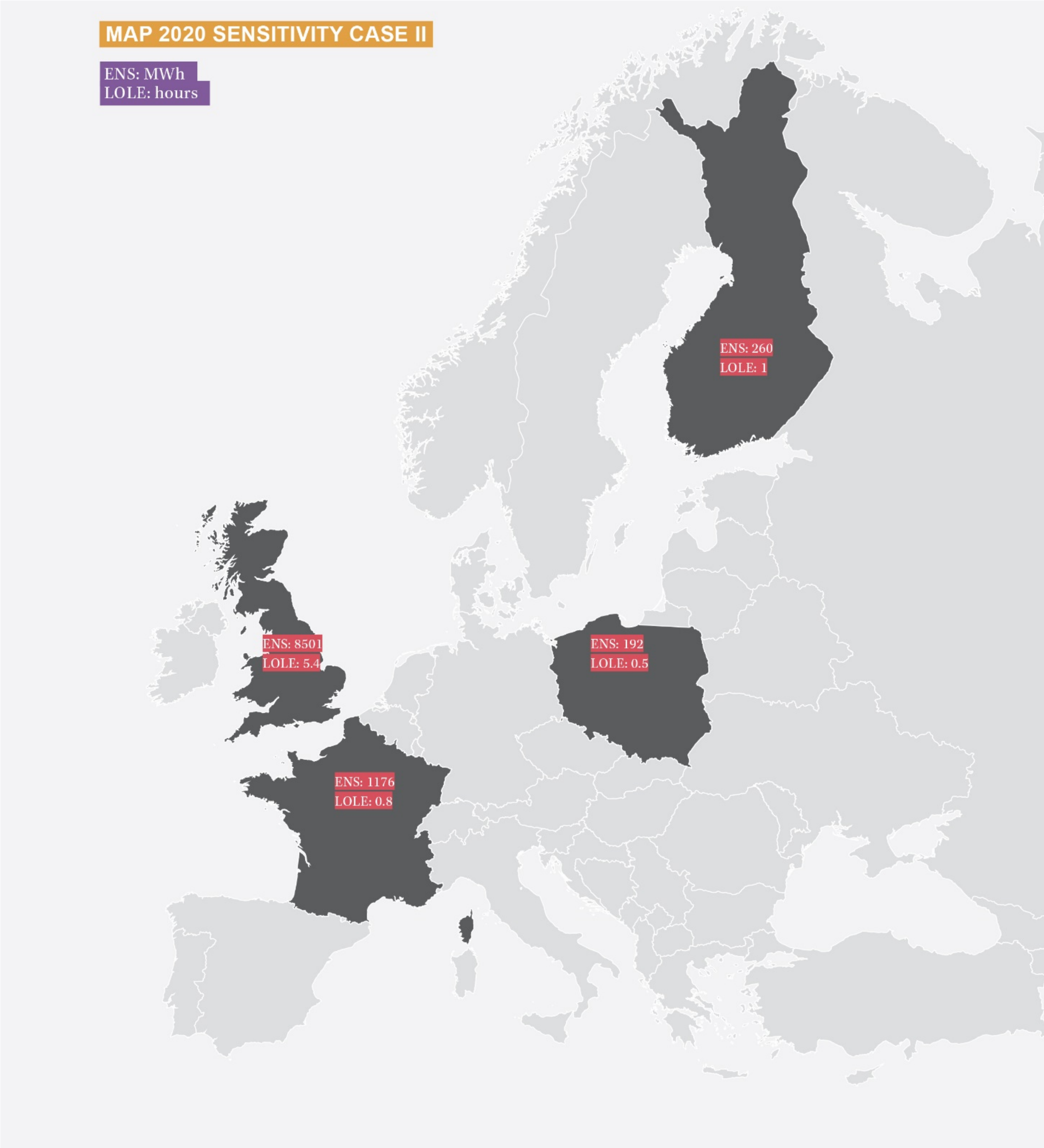

Figure 7 - 2020 Sensitivity II - Map representing countries ENS and LOLE (only for countries with average LOLE > 1 h)

Summary of Adequacy Indicators for 2025

The table below provides an overview of the values for Energy Non-Served (ENS) found for several countries within the **Pan-European perimeter and within the different simulations performed in 2025.**

If a country is not mentioned in the table below, it is because, no adequacy problems are observed for such country and then ENS and LOLE should be understood as being zero.

Table 3 - Summary table for year 2025 - Average ENS (S# denotes Simulator# results)

2025 BASE CASE[7]				
COUNTRY	ENS (MWh)	COUNTRY	ENS (MWh)	Sim.
BE	30676	NI	3804	S2
	51809		3118	S6
CH	0	PL	27	S2
	11811		1332	S6
DE	894	LU	4579	S2
	38792		4103	S6
DK	2232	IT	8978	S2
	6174		26237	S6
FI	8436	NL	1061	S2
	28722		3618	S6
FR	60872	NO	0	S2
	150439		2360	S6
GB	19690	SE	330	S2
	26802		2109	S6
IE	3220	TR	577	S2
	4555		11	S6

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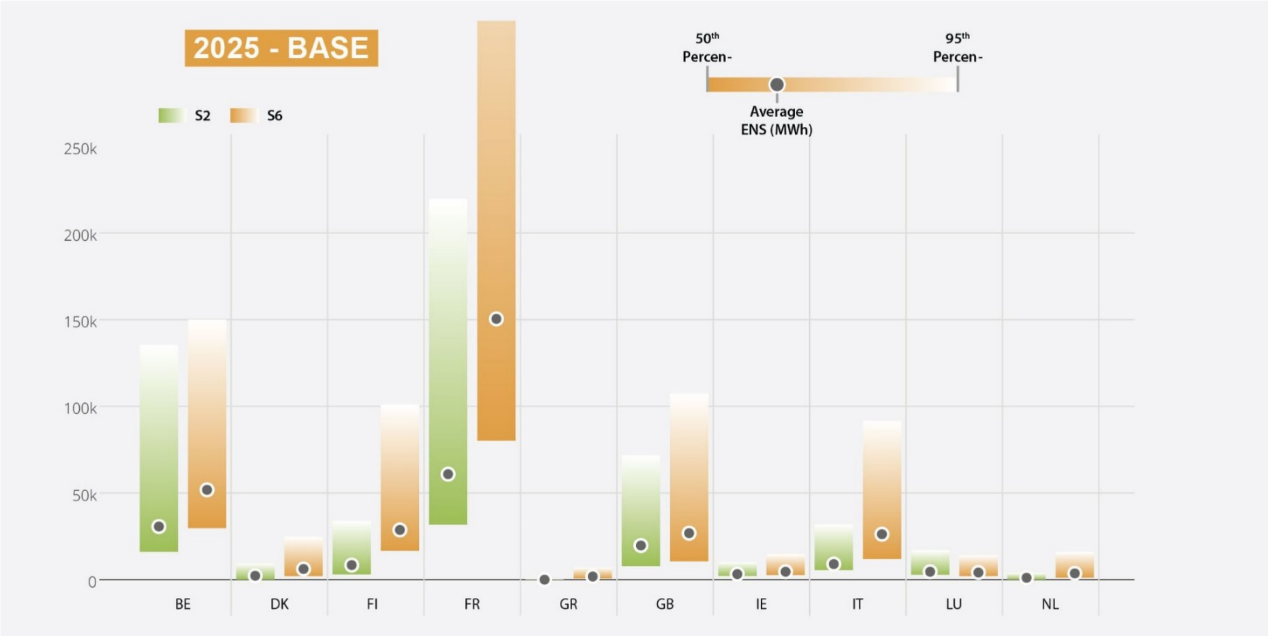

Figure 8 - 2025 ENS Base Case - P50, Average, P95 percentiles. (Note: Only for countries in red in the 2025 column of the 'Overview Table' - for further details see Chapter 5)

These **results are discussed in detail below.** Detailed LOLE figure**s** can be found in Chapter 5 also**.**

It is worth to highlight the following differences in the modelling assumptions between the different tools used for the 2025 simulation results obtained:

(S2) Hydro optimization includes perfect forecast knowledge of forced outages (FOR) of thermal units

(S6) Hydro optimization assumes to have only the knowledge of forced outages rates (FOR) of thermal units applied as a reduction of production capability and not depending from Monte Carlo sampling

The differences of the results between tools do not strive from a lack of robustness of the results of (one or several of the) tools but the different optimization logic used by the different tools. We consider important to highlight the slight sensitivity of the results to these modelling features, *with all data and other assumptions aligned between tools*. In particular these differences in the results should be understood **as a sensitivity in itself**, which indicate the importance of flexible generation, in this case hydro power mainly, to react against both variability due to RES but also unavailability of thermal generation due to force outages.

The reason for the differences is because of the hydro-optimisation and thermal plants' forced-outages modelling. In a conservative setting (S6) one assumes that one has only prior-knowledge of fixed forced outages (independent from the actual Monte-Carlo draws) and also would not be able to adjust the dispatch after the forced outage is known, while in a less conservative setting (S2) one assumes that one could foresee forced outages in advance and plan accordingly. This could respectively result in a different valuation of adequacy situations. In MAF this conservative setting by S6 results in potentially tight conditions in regions with significant amount of hydro installed capacities. However, the reality is in between these two extreme cases, because even though forced outages, according to their definition, cannot be known well in advance, still generators should know soon after the outage starts and be able to re-optimise their schedules accordingly. For hydro-countries, generators usually optimise their dispatch with a moving time-window, unlike a fixed window in the MAF simulations. With the well-known high flexibility of the hydro-plants, they can adapt very quickly based on the prevailing market and system conditions. The results here presented should be understood strictly within the assumptions above presented.

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2025 Base Case

Main messages

- These results provide an outlook of the main adequacy problems for a **2025** scenario assuming operational reserves **not** contributing to adequacy (e.g. operational reserves constraints on top of day-ahead (D-1) market considerations.
- The table above provides an overview of the average ENS found after the probabilistic simulations. **An increase in the occurrence of adequacy problems is observed in the 2025 scenario compared to the 2020 scenario**.
- **It should be noted that**:
- **Installed capacity**: A reduction of installed capacity of thermal power as well as an increase in RES is forecasted between 2020 and 2025 in the scenarios considered (see figures below in chapter 4)
- **Demand**: Forecasted demand increase is moderate at Pan-European level (1%) (see demand evolution – map in chapter 4). Demand increase does not seem the main driver for the increase in adequacy problems observed.
- **Transmission capacity**: Conservative assumptions regarding the evolution of transmission capacity between 2020 and 2025 have been used. Conservative assumptions relate to uncertainty in the commissioning dates of cross-border transmission capacity projects.
- **Sensitivity of the results**: Sensitivity runs performed on the interrelation between hydro power dispatch, pumped storage flexibility and availability of thermal production shows the importance of flexibility in the future power system in tight situations combining scarcity of power and unavailability of thermal generation due to maintenance and faults. This sensitivity affects the results for countries like **CH, PL and SE** significantly. The contribution of operational reserves improves the adequacy situation with respect to the results provided in the Base Case also for 2025 (see Chapter 5 for details).

- The results highlight the need for increased transmission capacity as well as increased usage of flexibility in the future power system evolution.

- These results should be understood strictly within the assumptions and data used in this chapter.

3 Methodology for adequacy assessment: stochastic market modelling to detect ‘*exceptional*’ situations

“Great things are done by a series of small things brought together”

(Vincent Van Gogh)

The methodology for adequacy assessments has been successfully implemented in four different market tools[5] working alongside each other. This has enabled the analysis of lots of different extreme situations by using a probabilistic approach. In the next section a general description on the tools employed for the modelling of adequacy analyses is given. This includes the main features one can expect from these tools. For the specific features which come with each individual tools employed in the study, please refer to the Appendix 3, where more detailed description for each different tool can be found.

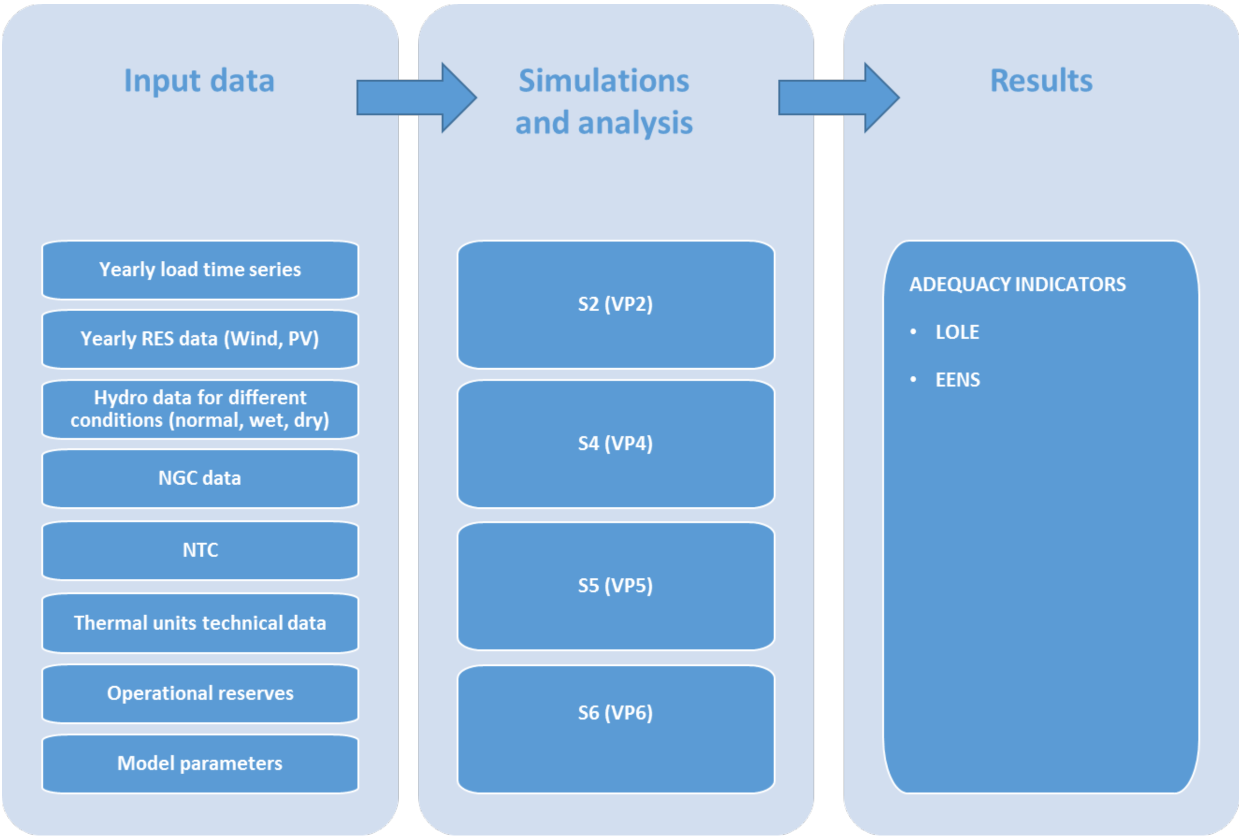

Figure 9 Methodology Summary, S# (VP#) denotes the Simulator (or Voluntary Party in ENTSO-E terminology).

[5] ANTARES, BID, GRARE, PLEXOS. See Appendix 3 for a short presentation of the tools.

In order to have a consistent data set, a common scenario is agreed upon: A harmonized and centralized Pan-European Market Modelling Data Base (PEMMDB) for market studies has been prepared based on national generation adequacy data and outlooks provided to ENTSO-E by each individual transmission system operator (TSO). The focus of the study is on two time horizons: years 2020 and 2025. For more detail description of the data set of scenarios used please refer to chapter 4.

A probabilistic approach: future supply and demand levels are compared by simulating the market operations of the European power system on an hourly basis over a full year. These simulations take into account the main contingencies capable of threatening security of supply, including:

- **outdoor temperatures** (which result in load variations, principally due to the use of heating in winter and cooling in summer; for more detail see **section 3.2**)
- **wind and photovoltaic power production** (see **section 3.3**)
- **unscheduled outages** of thermal generation units (**section 3.4)** and relevant HVDC interconnectors (see **section 4.2.1**)
- **maintenance schedules** (see **section 3.5**)
- **extended hydro database**, including **dry and wet hydro conditions** in addition to **normal hydro conditions**, and different probability of occurrence of these three (for more details, see **section 4.3)**.

According to the climatic correlations provided by ENTSO-E Pan-European Climate Data Base (PECD), a set of time series of correlated load / wind / solar production are used in the simulations. Furthermore, different types of hydro conditions, available capacity of units generating supply and reflecting various possible outcomes are created for each of the phenomena considered above. These series are then combined in sufficient numbers to give statistically representative results including shortages/scarcity situations (risk of demand not being met due to a lack of generation).

The main indicators used to detect these scarcity situations are referred to as main adequacy indicators and are described in **section 3.1.1**.

3.1 Advanced tools for Monte Carlo approach

Below you can find the overview scheme of the probabilistic Monte-Carlo approach followed in each scenario 2020 and 2025:

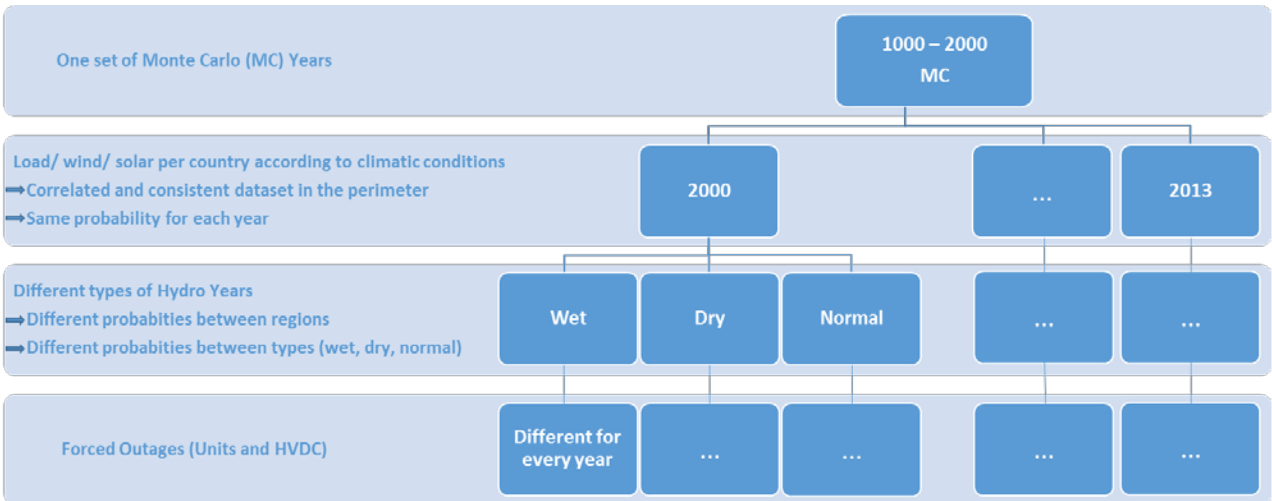

Figure 10 Graphical Illustration of the amount of Monte-Carlo years required for convergence of the results.

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For each scenario **2020** and **2025** of Net Generating Capacity (NGC) forecast, cross-border transmission capacity forecast and annual level of demand forecast, **1000-2000** Monte Carlo simulations have been performed by each of the 4 market modelling tools. These **1000-2000** Monte Carlo simulations are built by the following combinatorial process:

Each Monte Carlo simulation is built as follows: All **climate years (2000-2013)** are chosen one – by – one. Each climate year choice, meaning each combination of load (accounted temperature sensitivities), wind and solar time series, is combined with the three possible **hydro conditions (wet, dry, normal).** Each choice of climate + hydro condition is further combined with **200-300 realizations of Force Outages** of thermal units and HVDCs.

In general the tools employed are built upon a market simulation engine. Such market simulation engine is not meant for modelling or simulating the behaviour of market players, e.g. gaming, explicit capacity withdrawal from markets, etc., but rather meant for simulating marginal costs (not prices) of the whole system and the different market nodes. Therefore the main assumption is that the markets function perfectly.

The tools calculate the marginal costs as part of the outcome of a system-wide costs minimization problem. Such mathematical problem, also known as “Optimal Unit Commitment and Economic Dispatch”, is often formulated as a large-scale Mixed-Integer Linear-Programming (MILP) problem. In other words, the program attempts to find the least-cost solution while respecting all operational constraints (e.g. ramping, minimum up/down time, transfer capacity limits, etc..) . In order to avoid infeasible solutions, very often the constraints are modelled as “soft” constraints, which means that they could be violated, but at the expense of a high penalty, i.e. high costs. Most mathematical solvers nowadays are capable of solving large-scale LP problems with little computation time. However, with the presence of integer variables it is still common in commercial tools to solve the overall problem by applying a combination of heuristics and LP.

In the Pan-EU MAF 2016 study, the size of the problem, i.e. the number of variables and constraints was huge ~ thousands of each of them. The size increases with the optimization time horizon and the resolution. For the MAF 2016 study, the horizon of some optimization and / or constrains, e.g. hydro optimization, maintenances or fault duration, etc.., is a week, and the resolution of the simulation is hourly, i.e. given the constraints and boundary conditions the total system costs are minimized for each week of the year on an hourly basis. The weekly optimization horizon means that the optimal values for each hour of the whole year are calculated, with the optimization problem broken up on a weekly basis, in order to reduce the computation time. A weekly optimization horizon is also a common practice for market simulations at many TSOs for network planning. The latter means that the results such as generation output of the thermal and hydro plants, marginal costs, etc. are given per hour. This setting of the parameters is also the common practice for the market simulations which are conducted for ENTSO-E TYNDP and PLEF GAA.

These tools also have the functionality to include the network constraints to a different degree. Nowadays the status - quo approach for pan-European or regional market studies is based on NTC/ATC-Market Coupling (NTC/ATC MC). This means that the network constraints between the market nodes are modelled as limits only on the commercial exchanges at the border. This approach is used in this study.

The EU target model is based on Flow-Based Market Coupling (FBMC). In this model the network constraints are modelled as real physical limits on selected “critical branches”. Most TSO tools nowadays can perform FBMC, even though they have not been thoroughly tested for large-scale applications. There are also tools which can model the physical network explicitly including all the technical constraints such as contingencies, thermal and voltage constraints, therefore supporting what is commonly known as OPF (Optimal Power Flow). Such feature is not yet common in Europe since there is no agreement or plans for a regional scale application of nodal pricing. Possibilities to include Flow-Based Market Coupling (FBMC) for future MAF reports are being evaluated currently within ENTSO-E.

For this study four different models (referred later in the report as either Simulator# or VP#) were used in parallel. TSOs have expertise in using these tools and are able to capture the important features of their national or regional perimeter for the Pan-European simulations. Comparison of results between the different tools ensures quality and robustness of the inputs as well as of the results. Furthermore, full alignment of the results between different tools is not possible due to differences in the intrinsic optimization logic of the "Optimal Unit Commitment and Economic Dispatch" used by the different tools. These different features of the different tools are also exploited in the simulations to understand the sensitivity of the results to the different optimization objectives, *while the input data is identical* for all tools. The aim of the use of different models and the comparison of the model outputs is to create consolidated, representative and reliable results, while understanding their sensitivity to assumptions and modelling choices. The process is shown in next figure. The comparison of the results was done in four steps:

- Preparation of aggregated output data of the models
- Visualization of the output data in form of comparison charts
- Discussions and analyses within the MAF group
- Specification of actions regarding model or input data improvement

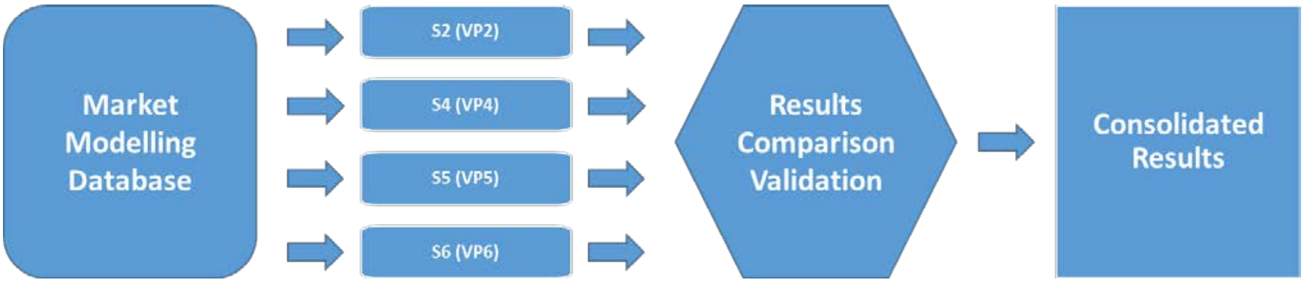

Figure 11 - Use of multiple models

The proposed probabilistic methodology presents a significant improvement with respect to the past deterministic ENTSO-E methodology based on capacity margins (see SO&AF 2015). Still the usage of the methodology in each MAF report, should be understood as an '*implementation release*' of ENTSO-E Target Methodology, which is in itself subject to constant evolution and further improvement. The expected improvements in further reports worth mentioning are: implementation of flow based modelling, the extension of the climate database to cover more representative samples of the climatic variations, which affect RES generation and hydrological conditions, and modelling of Demand Side Managements (DSM), etc..

3.1.1 Adequacy Indices

System adequacy is concerned with the existence of sufficient resources to meet the customer demand and the operating requirements of the power system. As a metric, so-called adequacy indices are used. These indices can be quantified as deterministic indicators (capacity margins) or as probabilistic indicators, according to the methodologies used for the adequacy assessments.

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With respect to the definition and scope of the indices of adequacy studies, three main functional zones of power systems are involved in the adequacy evaluation:

- Generation adequacy level (or hierarchical level I), which considers the total system generation including the effect of transmission constraints as NTCs.
- Transmission adequacy level (or hierarchical level II), which includes both the generation and transmission facilities in an adequacy evaluation.
- The overall hierarchical level (or hierarchical level III), which involves all three functional zones, from the generating points to the individual consumer load points, typically connected at the distribution level.

Traditionally, the adequacy indices can have different designations depending on the hierarchical levels involved in the adequacy study. In this edition of the MAF 2016 report, the focus is on the hierarchical level I, generation adequacy level and the results of the simulation are expressed in terms of the following indices:

1. **Energy Not Supplied or Unserved Energy (ENS)** [MWh/y] *ENS* is the energy not supplied by generating system due to the demand exceeding the available generating and import capacity.

$$\mathrm{ENS} = \frac{1}{N}\sum\nolimits_{j\in S} ENS_j \qquad (1)$$

where ENS_j is the energy not supplied of the system state j ($j \in S$) associated with a loss of load event of the j^{th}-Monte-Carlo simulation and where N is the number of Monte-Carlo simulations considered[6].

2. **Loss Of Load Expectation**[7] (h/y) *LOLE* is the number of hours in a given period (year) in which the available generation plus import cannot cover the load in an area or region.

$$\mathrm{LOLE} = \frac{1}{N}\sum\nolimits_{j\in S} LLD_j \qquad (2)$$

where, LLD_j is the loss of load duration of the system state j ($j \in S$) associated with the loss of load event of the j^{th}-Monte-Carlo simulation and where N is the number of Monte-Carlo simulations considered. It should be noted *LOLE* can only be reported as an integer of hours because of the hourly resolution of the simulation outputs. *LOLE* does not indicate the severity of the deficiency or the duration of the loss of load within that hour.

[6] ENS when referred to assessments performed for future forecasted scenarios of the power system evolution is often referred in the literature as *Expected* Energy Non-Served EENS. Although we skip the *Expected* from our nomenclature definition, the ENS reported here should be understood and an Expectation or Forecast value and **not** as actual ENS observed in historical statistics of actual power systems behaviour.

[7] When reported for a single Monte-Carlo simulation as the sum of all the hourly contributions with ENS, this quantity refers to the number of *hours (events)* within one year for which ENS occurs/is observed and this quantity should be referred to as *Lost of Load Event*. The quantity calculated in Eq. (2) refers to the *average over the whole MC ensemble of Events* and it therefore provides the statistical measure of the expectation of the number hours with ENS over that ensemble.

3. **Loss Of Load Probability** [%] *LOLP* is the probability that the load will exceed the available generation at a given time. This criterion only gives an indication of generation capacity and import capacity shortfalls and lacks information on the magnitude and duration of the outage.

$$\text{LOLP} = \sum_{i \in S} p_i|_{(C_i - L_i)<0} \qquad (3)$$

Where p_i is the probability that there is loss of load, C_i is the available Generation and L_i is the load of the system state i ($i \in S$) associated with the loss of load.

The proposed metrics above are quantified by probabilistic modelling of the available flexible resources. Additional indices to measure, for example, frequency and duration of the *ENS* or the power system flexibility, can be considered in future evolutions.

3.1.2 Probabilistic Indices and model convergence

With respect to the relation of the probabilistic indices and convergence of the models, when multiple Monte-Carlo simulations are conducted, these indices can also be expressed in average, minimum and maximum values accordingly. Any annual values can also be plotted as to construct a probability distribution curve.

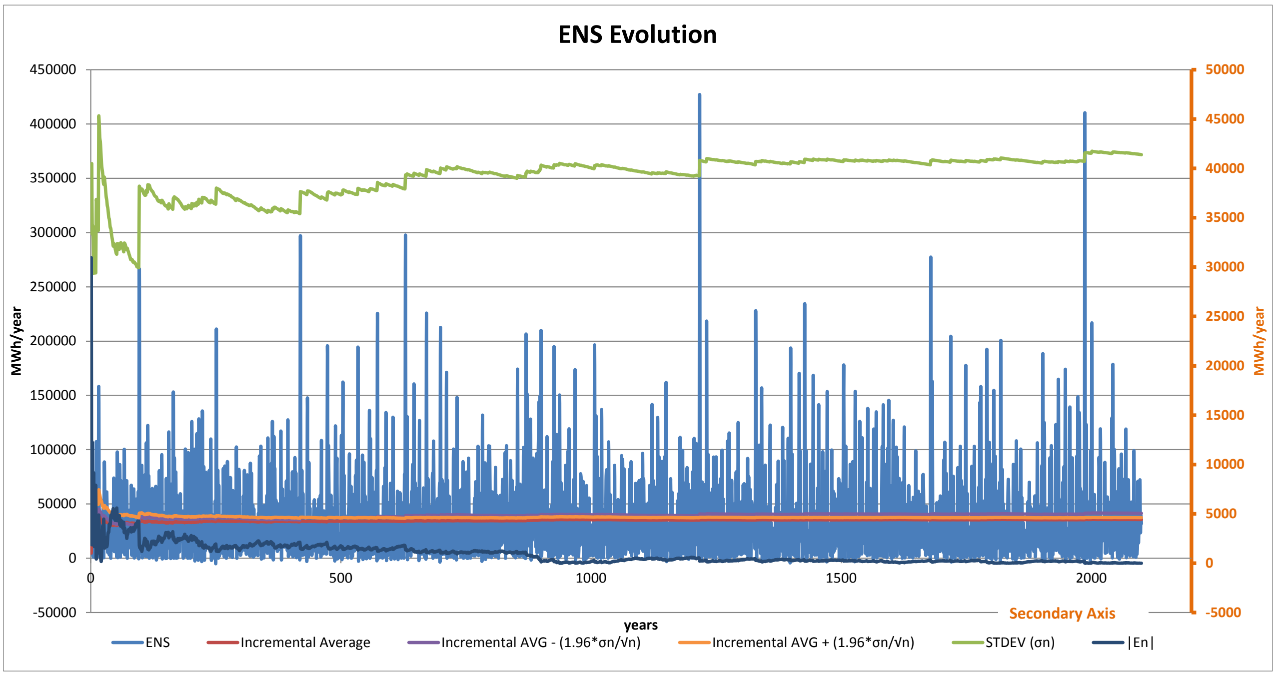


Figure 12 – Example of ENS convergence on all the Monte Carlo years

The trend of the moving average of *ENS* against the number of Monte-Carlo simulations (*N*) performed provides a good indication of the convergence of the simulations (example shown in Figure 12). When *N* is sufficiently large (i.e., when The Strong Law of Large Numbers and Central Limit Theorem hold), the error between the expected value and its average exhibits a Gaussian distribution and its upper bound with a probability of 95% can be calculated using the following formula:

$$|\varepsilon_n| \leq 1.96 \frac{\sigma}{\sqrt{n}} \qquad (4)$$

Respectively the confidence interval can be calculated using the following formula:

$$\left[\bar{X}_N - 1.96 \frac{\sigma_N}{\sqrt{N}}, \bar{X}_N + 1.96 \frac{\sigma_N}{\sqrt{N}}\right] \qquad (5)$$

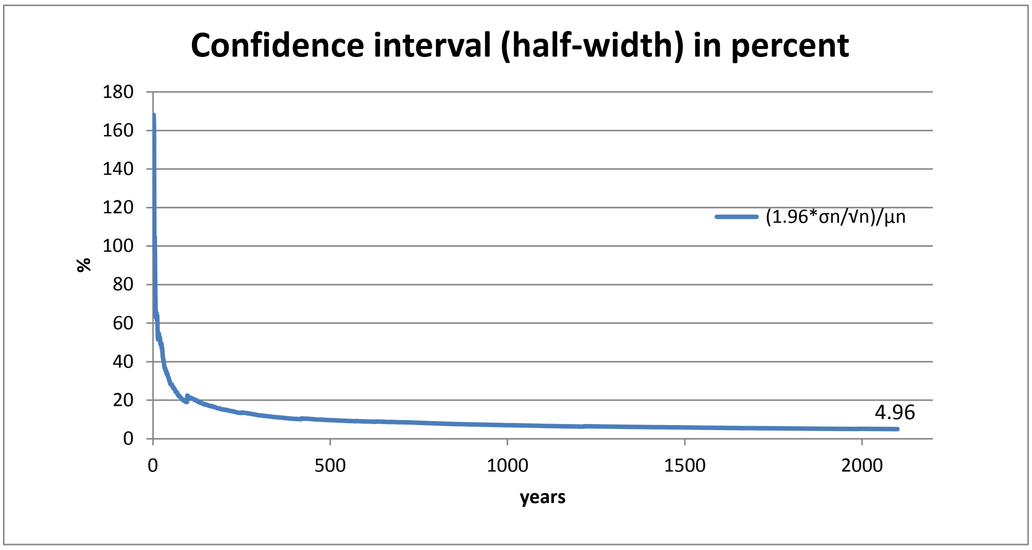


Figure 13 – Example of confidence interval reached by the simulations in MAF 2016

Some inputs and parameters can have significant impact on the numerical results of these indices and their convergence:

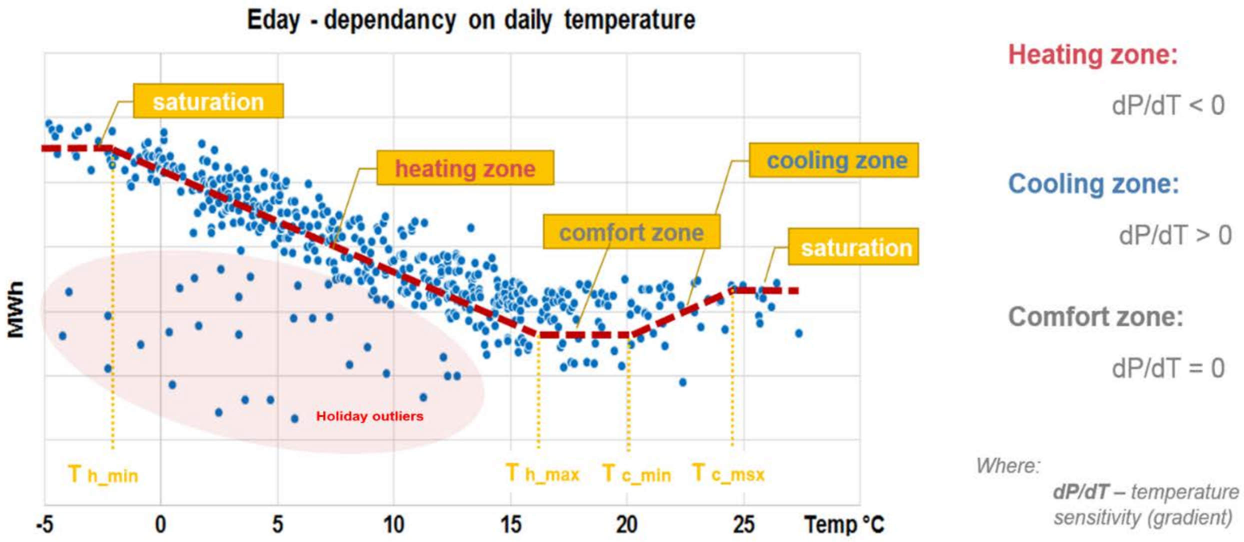
- **Hydro power data usage and modelling** can have significant impact on the numerical results of these indices.
- **Net Transfer Capacities (NTC):** conservative assumptions on NTC values compared to the values from EP2020 in TYNDP2016 have been chosen since these assumptions allow the detection of risks related to situations when individual countries are dependent on *simultaneous imports in scarcity situations* and highlight the importance of interconnections for Pan-European security of supply.
- **Outages and their modelling**: this refers to both maintenance and forced outages. In order to understand the impact of forced outages, which are random by default, it is important for all the tools to use one commonly agreed maintenance schedule. This maintenance schedule should respect the different constraints specific to the thermal plants in different countries, as provided by TSOs.

In order to obtain a satisfactory analysis of the influence of different input, parameters, outages and modelling with the use of different tools, various sensibility analyses have been conducted in this report, as presented in the Section 5.

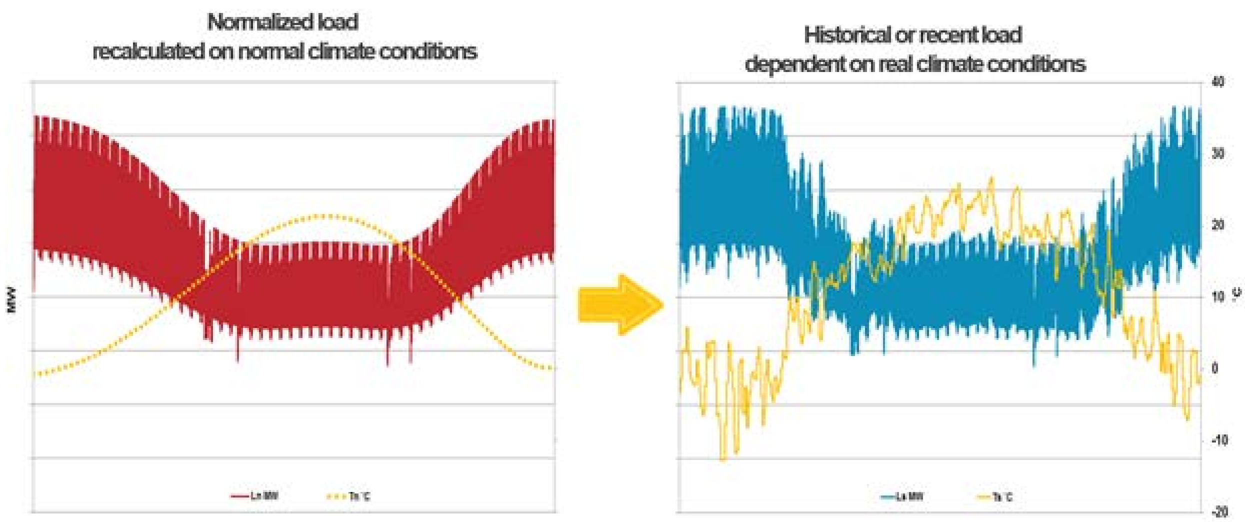
3.2 Temperature dependency of load

Sensitivity of load to temperature is one of the main methodological items to be considered for adequacy assessments. A widespread use of electric heating (cooling) is the primary factor explaining the surge in demand observed during cold spells in winter and/or heat waves in summer and leads to high demand fluctuations from one year to the next. One fundamental requirement for the probabilistic modelling performed here is the correct simulation of weather changes influencing the stochastic behavior of the electric load.

Different kinds of temperature dependencies are shown on the picture below. In the example below, a linear model is presented to define sensitivity zones determined by the temperature gradient dP/dT. The resulting load change dP can be positive, negative or neutral in each particular zone, depending on the simulated (or investigated) temperature fluctuation dT.



In practice it means that for each simulation run, preparation of individual time series containing the hourly load values with respect to the real climate conditions is performed. Furthermore, it is necessary to transpose and calibrate the load values from normal temperature conditions to simulated temperature situations in accordance with the applied climate model and the observed/expected records – see the following pictures for details.



The equation used to transpose the load values from normal temperature conditions to simulated real situations is the following:

$$\boldsymbol{L}(h) = \boldsymbol{Lnorm}(h) \pm \Delta\boldsymbol{L}(\Delta t°\mathrm{C}, h)$$

where: $\boldsymbol{L}(h)$ … is the hourly load in the simulated climate conditions (blue curve above)
$\boldsymbol{Lnorm}(h)$ … is the load in the normal climate conditions (red curve above).
$\Delta\boldsymbol{L}(\Delta t°\mathrm{C}, h)$ … is the hourly load fluctuation under the temperature change Δt.

Temperature changes $\Delta\mathbf{t}$ can be considered as daily average increase or decrease of the real temperature compared to daily temperature normal:

$$\Delta \boldsymbol{t} = \boldsymbol{T}pecd - \boldsymbol{T}norm$$

where: $\boldsymbol{T}pecd$ … values for each day of simulated climate years we can obtain value from PECD database (see paragraph 3.3).
$\boldsymbol{T}norm$ … represents 30 year average of the daily temperature normal. Application of the 50 years temperature normal is optional.

Different methods have been explored and tested to identify the most suitable definition taking into account each country's specificities. We provide here a quick overview:

Linear approximation

1) **Eday linear**

This method is based on the simulation of daily energy change according to daily energy sensitivity $\boldsymbol{dE}day$. Based on this assumption we can express:

$$\Delta \boldsymbol{E}day = \boldsymbol{dE}day * \Delta t$$

where: $\Delta \boldsymbol{E}day$ … is the simulated daily energy change in MWh
$\boldsymbol{dE}day$ … is the daily energy sensitivity in MWh/°C.
Δt … is the daily temperature change in °C.

For each hour we can calculate linear increase (or decrease) of the load

$$\Delta \boldsymbol{L}(h) = \boldsymbol{L}norm(h) * (\Delta \boldsymbol{E}day/\boldsymbol{E}day\_norm)$$

where: $\boldsymbol{L}norm(h)$ … is the load in the normal climate conditions for given hour *h*,
$\boldsymbol{E}day\_norm$ … is the daily energy of normalized load for given day.

2) **Pmin, Pmax linear**

This method is based on the change of extremes of daily load - *Pmin, Pmax,* applying the load sensitivity in daily extremes – maximum and minimum. Such dependency can be expressed by the following formulas:

$$\Delta \boldsymbol{P}max = \boldsymbol{dP}max * \Delta t$$

$$\Delta \boldsymbol{P}min = \boldsymbol{dP}min * \Delta t$$

where: $\Delta \boldsymbol{P}max$ … is the simulated change of daily maxima in MW
$\Delta \boldsymbol{P}min$ … is the simulated change of daily minima in MW
$\boldsymbol{dP}max$ … is the load sensitivity of daily maxima in MW/°C
$\boldsymbol{dP}min$ … is the load sensitivity of daily minima in MW/°C
Δt … is the daily temperature change in °C.

For each hour we can calculate the increase (or decrease) of load ΔP in given hour using a rescaling formula of daily diagram. Application of stretch and linear rescaling methods is explained in next paragraph.

$\Delta \boldsymbol{L}(h) = \boldsymbol{L}norm(h) * \boldsymbol{dP}resc + \boldsymbol{P}add$ …. for "**stretch**" rescaling method or
$\Delta \boldsymbol{L}(h) = \boldsymbol{L}norm(h) * \boldsymbol{dP}resc$ …. for **linear** rescaling method.

where: $\boldsymbol{L}norm(h)$ … is the load in the normal climate conditions for a given hour *h*.

Simultaneously for rescaling coefficient ***dPresc*** and constant ***Padd*** we can use following equations:

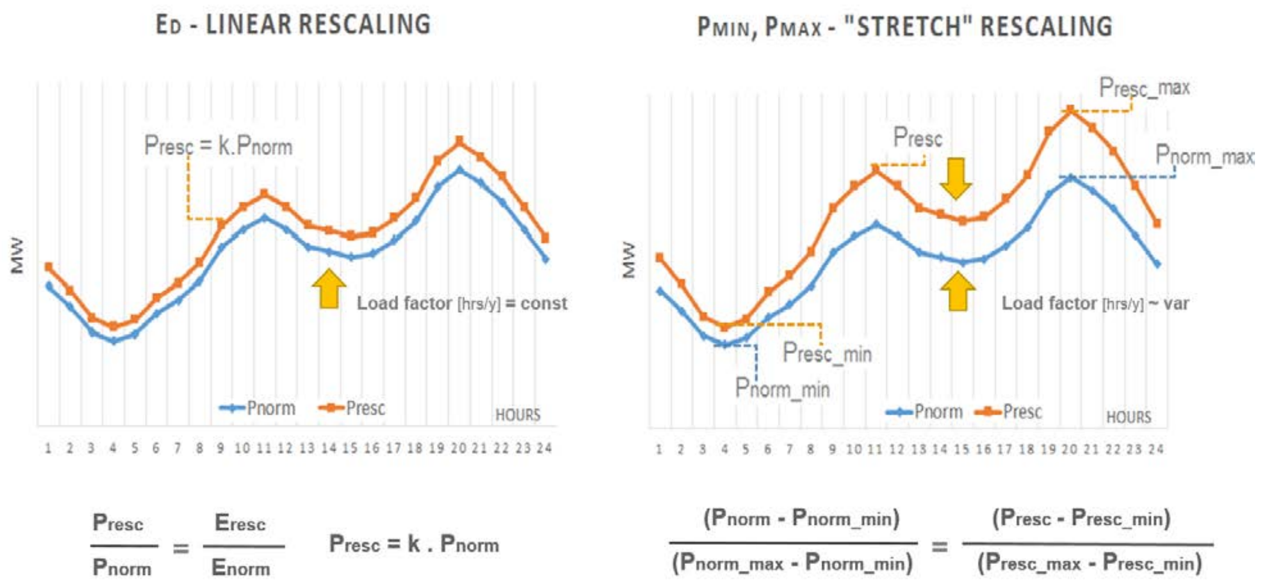
$$\boldsymbol{dP}resc = (\Delta \boldsymbol{P}max - \Delta \boldsymbol{P}min)/(\boldsymbol{P}max - \boldsymbol{P}min)$$
$$\boldsymbol{P}add = \Delta \boldsymbol{P}min - \boldsymbol{P}min * \boldsymbol{dP}resc$$

P*max*, ***P****min* are daily minimum and maximum of the normalized load and $\Delta \boldsymbol{P}_{max}$, $\Delta \boldsymbol{P}_{min}$ are the changes according to the given temperature fluctuation.

Load diagram rescaling methods:

Calculation methods for daily diagram rescaling together with the meaning of rescaling coefficients are presented below. On following picture $\boldsymbol{P}_{norm}$ represents load in normal climate conditions before rescaling and $\boldsymbol{P}_{resc}$ is a load after rescaling on simulated (or investigated) climate conditions.

In case of linear rescaling is $\boldsymbol{P}_{add} = 0$ and $\boldsymbol{dP}_{resc} = \Delta \boldsymbol{E}day/\boldsymbol{E}day$, eventually $\Delta \boldsymbol{P}max/\boldsymbol{P}max$. Applying this method the utilization of load maximum (so called load factor) will be constant in comparison to stretch method when shape of the diagram could be varying in the reaction to wider spread between minimum and maximum of the load.



Polynomial approximation

3) Eday cubic

In this case we can use the cubic polynomial approximation for daily energy change modelling according to following formula:

$$\Delta \boldsymbol{E}day = A * \left(\boldsymbol{T}pecd^3 - \boldsymbol{T}norm^3\right) + B * (\boldsymbol{T}pecd^2 - \boldsymbol{T}norm^2) + C * (\boldsymbol{T}pecd - \boldsymbol{T}norm)$$

Where: *A*, *B*, *C* are the cubic polynomic coefficients and the hourly change of load ΔL(h) is calculated the same way as in method 1.

4) Pmin, Pmax cubic

In this case we can use the cubie polynomial approximation of load sensitivity for the change of extremes of daily load - *Pmin*, *Pmax*, according to following formulas:

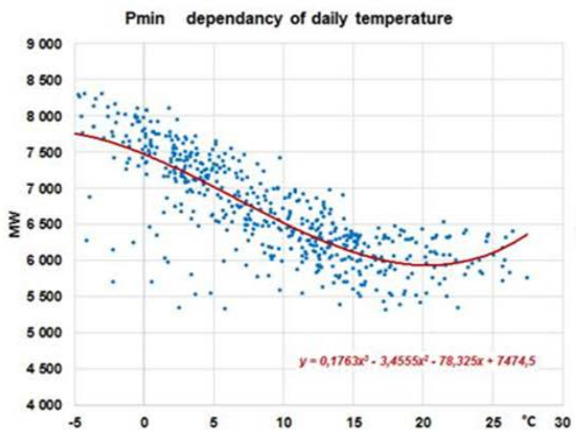
$$\Delta \boldsymbol{P}max = A1 * \left(\boldsymbol{T}pecd^3 - \boldsymbol{T}norm^3\right) + B1 * (\boldsymbol{T}pecd^2 - \boldsymbol{T}norm^2) + C1 * (\boldsymbol{T}pecd - \boldsymbol{T}norm)$$
$$\Delta \boldsymbol{P}min = A2 * \left(\boldsymbol{T}pecd^3 - \boldsymbol{T}norm^3\right) + B2 * (\boldsymbol{T}pecd^2 - \boldsymbol{T}norm^2) + C2 * (\boldsymbol{T}pecd - \boldsymbol{T}norm)$$

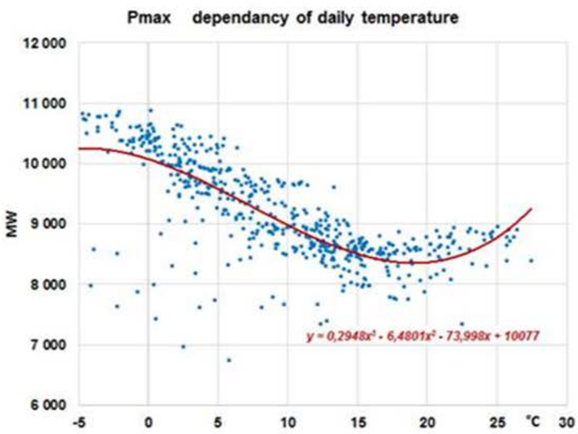
A1, B1, C1 or (A2, B2, C2) are cubic polynomic coefficients for the given extreme of the daily diagram. For each hour we can calculate the increase (or decrease) of load $\Delta L(h)$ using the rescaling formula as described in method 2.

Temperature sensitivities:

Sensitivity linear parameters ***dE**day*, ***dP**min* and ***dP**max* we can receive as an assessment of dependency of historical values of daily energy of load (daily consumption), daily load minimum, and maximum on daily temperatures.

Example of cubic polynomial approximation is shown on the pictures below:





For the current MAF we used method 1 or 2. Currently we are evaluating the application of cubic polynomial approximation for selected countries, which could be used in forthcoming MAF reports.

3.3 Pan-European Climate Database (PECD)

The use of Pan-European Climate Database (PECD) was an important methodological improvement achieved by ENTSO-E since the TYNDP 2014 framework.

Since the level of wind and solar energy exploitation is widely different across European countries, the availability of retrospective time series derived from measurements is limited to a few countries. In addition, there is a need of modelling input covering the projected new installations for which no measurements are available, in order to include their output in the prospective studies.

PECD load factor and temperature datasets (synthetic hourly time series derived from climate reanalysis and WRF models) enable a coherent simulation of variable RES production and weather-dependent load variation. The currently available time series delivered by Technical University of Denmark (DTU) cover the period of years 2000-2013.

For adequacy assessment purposes, the modelling of extreme events with potential impacts on security of supply is of key importance. Taking into account the evolution of the energy mix (i.e. growing development of renewable energy sources and increased reduction of conventional power plants) it has been identified the need to extend the PECD to cover more representative samples of the climatic variations and, in particular, higher statistical representativeness of extreme climate and calendar events such as cold spell, heat waves, extreme low wind conditions, solar eclipses, etc.

ENTSO-E is therefore procuring a new Pan-European Climate Database (PECD 2.0) extended by a number of additional countries and climate years, available from existing global climate reanalysis models of a higher temporal resolution (beginning from years 1982 to 2015).

At the time during the preparation of this report, PECD 2.0 is still under consolidation and was not ready for the probabilistic runs in MAF 2016. It will be used starting from the next ENTSO-E publication (Winter Outlook 2016/17, MAF 2017 and TYNDP 2018). It should be noted that the extension from 14 years of climate conditions to 35 years will cause a significant increase in the computational requirements of the probabilistic simulations to be performed and such effort should not be underestimated when planning for future assessments.

ENTSO-E PECD v2 consists of the following data sets:

Wind speed, radiation and nebulosity time series

- Hourly average reference wind speed at 100 m for each market node [m/s], to be calculated according to the formula provided:

$$Average\ reference\ wind\ speed\ (t, market\ node) = \sqrt[3]{\frac{1}{n}\sum_{i=1}^{n}\left(\sqrt{U_{t,i}{}^{2} + V_{t,i}{}^{2}}\right)^{3}}$$

t: time [hour]
U and V: wind components at 100 m height [m/s]
n: total number of grid points in the market node
i: grid point

- Hourly average global horizontal irradiance for each market node [W/m^2]
- Hourly average cloud cover (nebulosity) for each market node [okta]

Onshore, offshore wind and solar PV load factor time series

- Hourly normalized load factor time series for onshore and (if applicable) offshore wind production for each market node [-]
- Hourly normalized load factor time series for solar PV production for each market node [-]

Load factor: Percentage of production compared to installed capacity, expressed as a dimensionless ratio.

Concentrated Solar Power (CSP) load factor time series

- Hourly normalized load factor time series for concentrated solar power (CSP) for each market node where relevant [-]

Temperature time series

- Hourly city temperature time series for the list of cities provided [°C]
- Population (and/or load) weighted average temperature for each market node [°C]

3.4 Other relevant parameters

To allow a more accurate reflection of the diversity of generation technologies and bring the simulation's behaviour, especially the behaviour of simulated power plants and HVDC lines, closer to the operation in practice, basic parameters such as Net Generation Capacity (NGC), Number of Units and other additional technical parameters have been taken into account in the data collection. Some of these parameters present boundary conditions or thresholds that the simulators must fulfil during the simulations.

Availability of the power system elements is included in the simulation in two ways: i) Forced Outages and ii) Planned Outages. In the MAF, availability is considered on thermal power plants active in the market and HVDC lines.

i. **Planned outages**, refer to maintenance, and are defined as a number of days, on an annual basis, that a given unit (blocks of-) is expected to be offline due to maintenance. In MAF 2016, further restrictions regarding the minimum percentage of the outages which can occur in each season of the year, with focus of winter and summer, as well as the maximum number of simultaneously offline thermal units allowed within each month of the year was specified by TSOs. Within these restrictions, an optimized maintenance schedule, common to all modelling tools, is prepared. Optimization of the maintenance schedule refers to the minimization of number of units (simultaneously) in maintenance and the optimal distribution of the maintenance schedules to reduce the occurrence of potential adequacy problems, while respecting the constraints provided by TSOs on their national power system.

ii. **Forced outages** are represented by the parameter *Forced Outages Rate* (FOR) which defines the annual rate of forced outages occurrences of thermal power plants or HVDC lines. Forced outages are simulated by random occurrences of outages within the probabilistic Monte Carlo scheme, while respecting the annual rate defined. Simulated random forced outages are useful to assess the impact of availability of base-load thermal generation and its relation with available flexible thermal and hydro generation, renewable generation and the ability of areas under adequacy problems to cope with problems also by means of imports. Simulating the forced outages allows to test the resilience of a given area subject to such contingencies, potential adequacy problems that might occur and the ability of the area to share power (*via* spot market power and/or reserves).

Minimum stable generation (MW) is a parameter defining the technical minimum of the power output of a unit. The simulation does not allow the unit to run under this limit. It is defined by a percentage of the maximal power output of the unit.

Ramp up/down rates (MW/h) are defining the ability of thermal power plant, which is already in operation, to increase/decrease its generation output within the range of its stable working area, which is limited from the bottom by the minimum stable generation parameter and by the maximum power output from the top.

Minimum Up Time parameter defines the minimum number of hours a unit must stay in operation before it can be idled.

Minimum Down Time parameter defines the minimum number of hours a unit must remain idle before it can be restarted. These parameters guarantee the units will not be simulated in one hour in operation and the next hour out of operation to put it the following hour back into operation, if this kind of operation is not natural for the unit.

In addition to the main characteristics, other thermal characteristics have also been defined in the PEMMDB to allow a more accurate reflection of the diversity of the different generation technologies.

Common fuel and CO2 price assumptions:

A global set of values for fuel and CO_2 prices, as shown in the table below, is used for the whole Pan-European parameter. These values are taken from the World Energy Outlook 2013 for year 2020 for the IEA „Current Policies" scenarios.

Table 4 - fuel and CO_2 prices

Expected Progress 2020	Fuel prices (€/ net GJ)
Nuclear	0.46
Lignite	1.1
Hard coal	2.86
Gas	8.9
Light oil	15.6
Heavy oil	12.32
Oil shale	2.3
CO_2 prices (€/ton)	11
Source [1] World Energy Outlook 2013	IEA "Current Policies"

ENTSO-E welcomes interaction with relevant stakeholders to further improve the level of details of the above mentioned data, for future releases of the MAF report.

3.5 Operational reserves modelling

In the simulations considered in the MAF report, a certain capacity from the provided Net Generation Capacity (NGC) is considered to cover each TSO's reserve requirements. In the *Base Case* simulations, this capacity is considered as not contributing to adequacy (*D-1 situation*), while in the *Sensitivity* simulations, this capacity is assumed to contribute to adequacy *(real-time situation)*.

Further assumptions regarding the modelling of operational reserves might be considered in future reports, in line with the implementation of the pertinent Network Codes, and further considerations regarding the impact of sharing operational reserves on a real time basis, across synchronously-connected countries in ENTSO-E.

3.6 DSR & DSM

No explicit modelling of DSM/DSR has been performed in MAF 2016. Potential for load reduction capabilities has been however collected from TSOs. Although for some TSOs, these figures do present a view on market based demand side response, meaning that if prices are getting high, some consumers will not consume, in general the figures collected present last resort emergency capabilities available to TSOs, rather than estimates for a future market for DSM. Due to the heterogeneity of the available data, these figures have been used only in relation to the discussion of the results.

For this edition of the MAF report, the assumption of not considering DSM is still sensible since the main purpose of the report has been to quantify the risk of load not being met by available generation and imports within conservative analyses and assumptions by the implementation of probabilistic methods.

In future reports it may be possible to model DSM, in the following ways**,** within the different possibilities with current data/models:

- Load management → model as extra generation unit at the end of the merit order.
- Load management → take into account in the load profile as load reduction (ex-ante).
- Peak shaving → collect data for the potential of peak shaving for all time frames (2020/2025) and take this into account in the load profile (ex-ante)
- Modeling of peak shaving by some sort of ‘pump storage’
- Possible extra development to model demand price elasticity → main difficulty of this approach being to obtain high quality of data regarding the relation between volume and duration of demand reduction as a function of the electricity price; once such a data is procured, consulted and consolidated, adaptation of the models, although needed, is feasible. The idea is that during the hours where there is a risk to have ENS, the tool’s algorithm should be able to verify if it is possible activate DSM for a sufficient amount of power and optimize its deployment.

For any of the possibilities mentioned above, **detailed figures relating the volume and duration of load reduction available at peak load and as a function of the electricity price are needed**.

ENTSO-E welcomes interaction with relevant stakeholders to define the relevant figures above mentioned, for use in future releases of the MAF report.

4 Data Assumptions[8]

The MAF report concentrates on adequacy forecasting by the use of probabilistic assessments. Unlike previous forecast reports, i.e. SO&AF, in MAF 2016 a single scenario can be found for 2020 and 2025. The scenarios are referred to as "Expected Progress/ Best Estimate" scenarios. Format of the collected data is exactly the same like for TYNDP 2016 data collection process. The Expected Progress scenario, in the MAF 2016 edition, covers two years, 2020 and 2025 with the following assumptions:

1. Data for the year 2020 should be treated as conjunction point with TYNDP 2016. It is expected that MAF data for 2020 will be in line with TYNDP 2016 data in 2020 Expected Progress scenario. Nevertheless differences can be observed due to fact that data for MAF 2016 was gathered in January – February 2016, while data for TYNDP 2016 was collected in October - November 2014. For mid-term adequacy assessments, use of the most 'up-to-date' data from each TSO is recommended.

2. Data for the year 2025 should be understood as ideally mid-term conjunction point for TYNDP 2018 and should be based on TSO best estimate forecasts of development, following the same logic as used for the MAF 2016 - 2020 Expected Progress scenario but extended to 2025. Note that 2025 data was not collected for TYNDP2016.

According to the principles set out by ENTSO-E for common and consistent data collection, all TSOs have provided data considering to their best knowledge the evolution of the generation mix in their country. Taking into account the assumptions described above, it is expected that development of each generation subcategory as presented in the MAF dataset provides the most probable scenario according to TSO regarding the evolution of the power system in each country. Note that generally speaking, when TSOs provide their best estimate forecast regarding net generating capacity (NGC) and demand evolution, they typically use information provided to them by their national market parties, generators and in some cases data approved first by their national regulatory agencies. TSOs were asked to apply the best of their knowledge on the "economic viability" of the scenarios provided for MAF. Nevertheless it cannot be 100% guaranteed that the forecasted generation mix here used, will be economically viable in 2020 and 2025. ENTSO-E and TSOs are aware of the importance of these assumptions regarding the definition of the scenarios and ENTSO-E's process for a common and consistent data collection is being revised to improve the quality of the scenarios used and possibly assess sensitivities around those scenarios. ENTSO-E therefore welcomes interaction with relevant stakeholders regarding input data (see sections 3.4 and 3.5 above) which affects the 'likelihood of units to run and stay online' within the market modelling assessments performed in MAF, since these input data items are crucial to perform any sensible sensitivity regarding 'viability' of the (central) best-estimate scenarios collected by TSOs.

4.1 Scenario main data differences 2020 vs 2025

The evolution of generation resources at ENTSO-E level[9] between 2020 and 2025 is presented below. These figures show details of generation structure in each country in 2020 and 2025 both in general terms as well as in relative (percentage %) terms.

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[8] The data sets used for the 2020 and 2025 simulations are provided together with the MAF 2016 report (see '**MAF 2016 market modelling data.xlsx**')

[9] ENTSO-E level results include here Turkey, which is currently being considered as ENTSO-E observer member.

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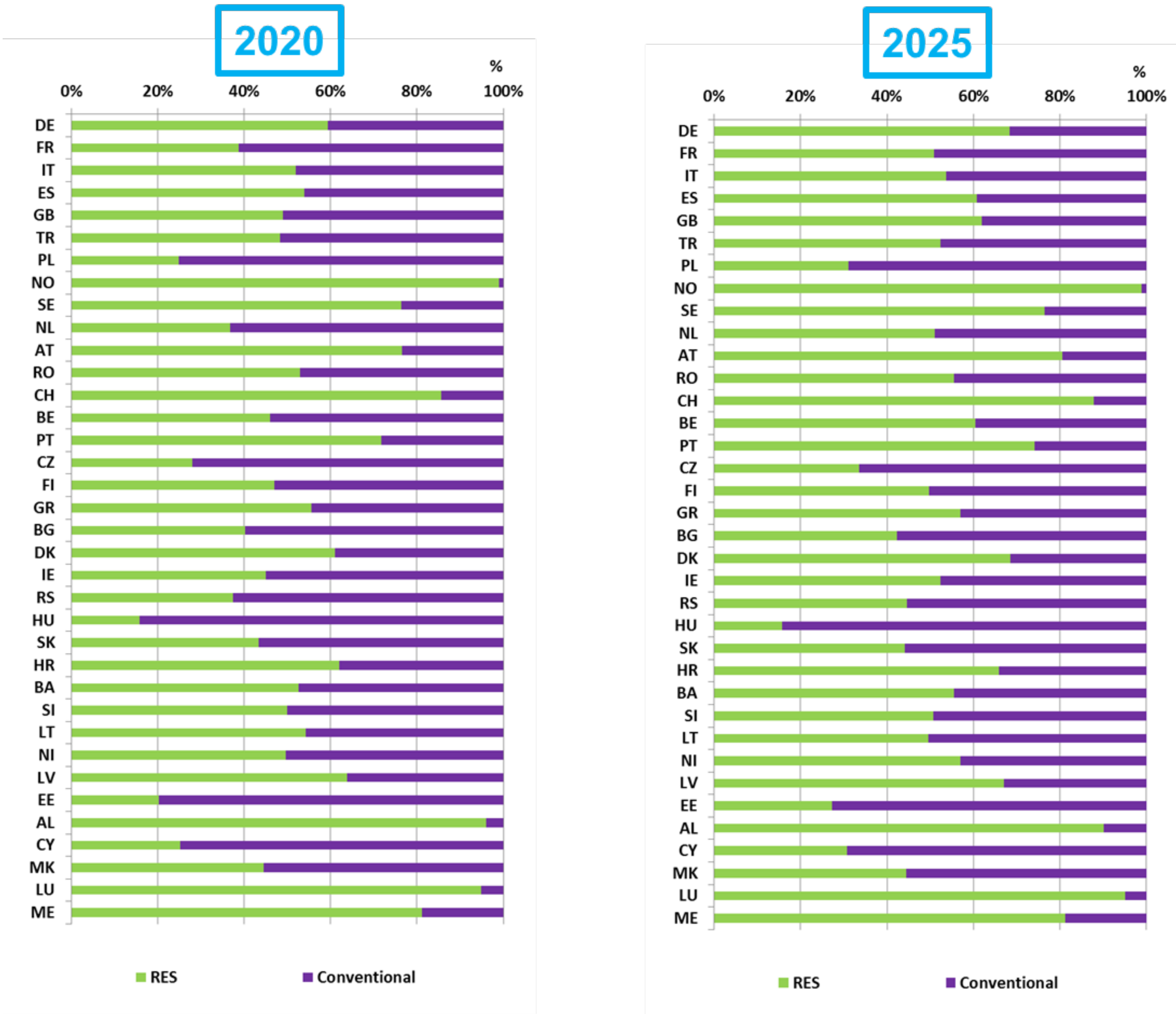

Figure 14 - Comparison Generation Mix: RES (green) vs Conventional (purple) - 2020 (left) - 2025 (right)

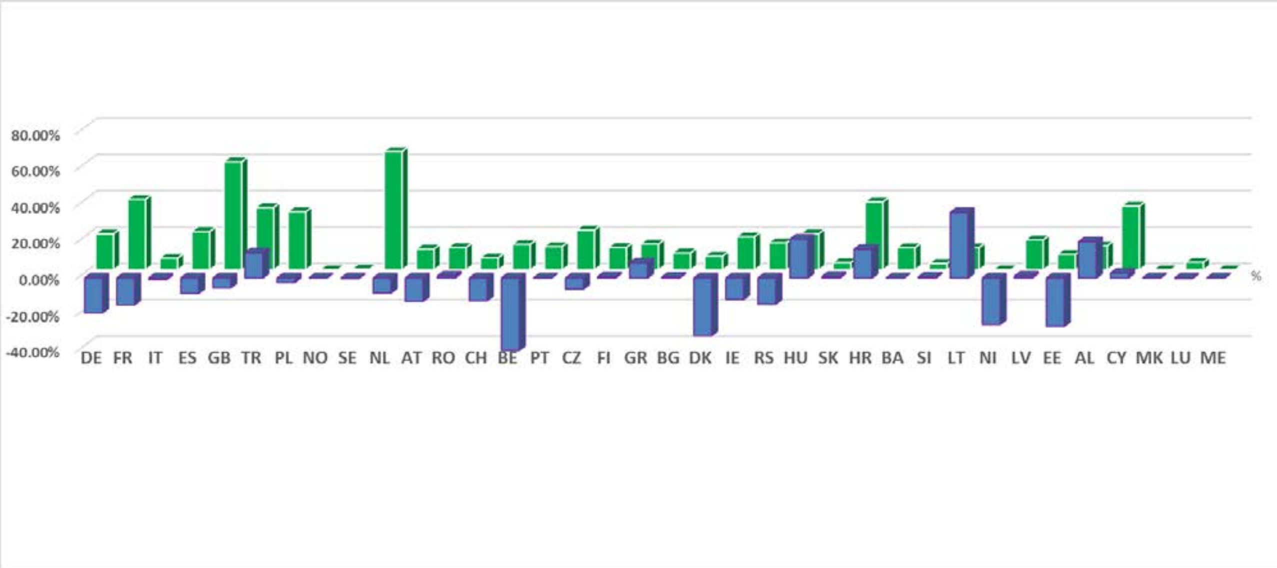

Figure 15 - Relative change (%) of Generation Mix between 2020 and 2025: Green (RES) & Purple (Conventional)

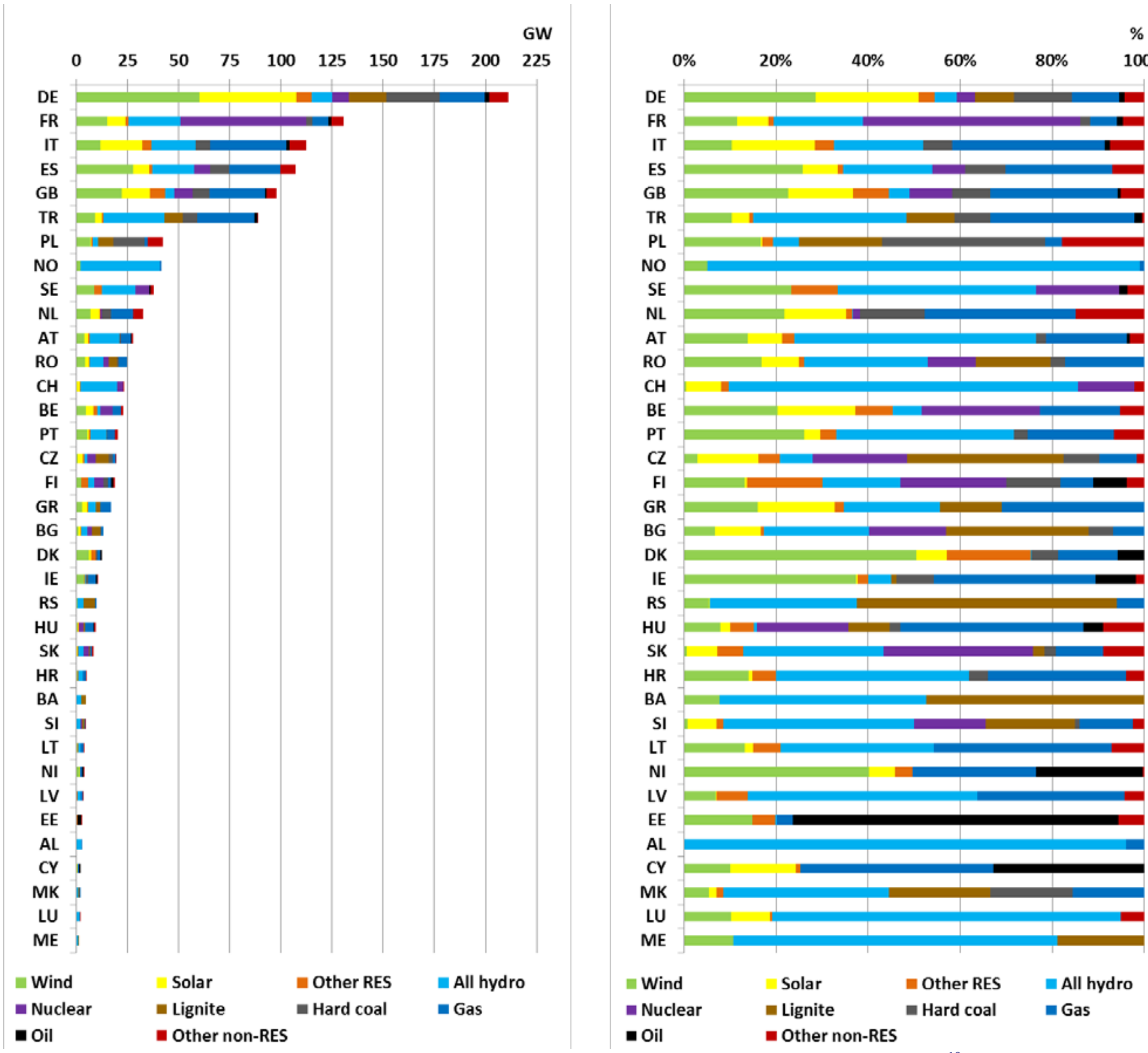

Figure 16 – Detailed Net Generating Capacity structure per country, year 2020[10]

[10] NI abbreviation refer to Northern Ireland, therefore in GB results Northern Ireland is excluded.

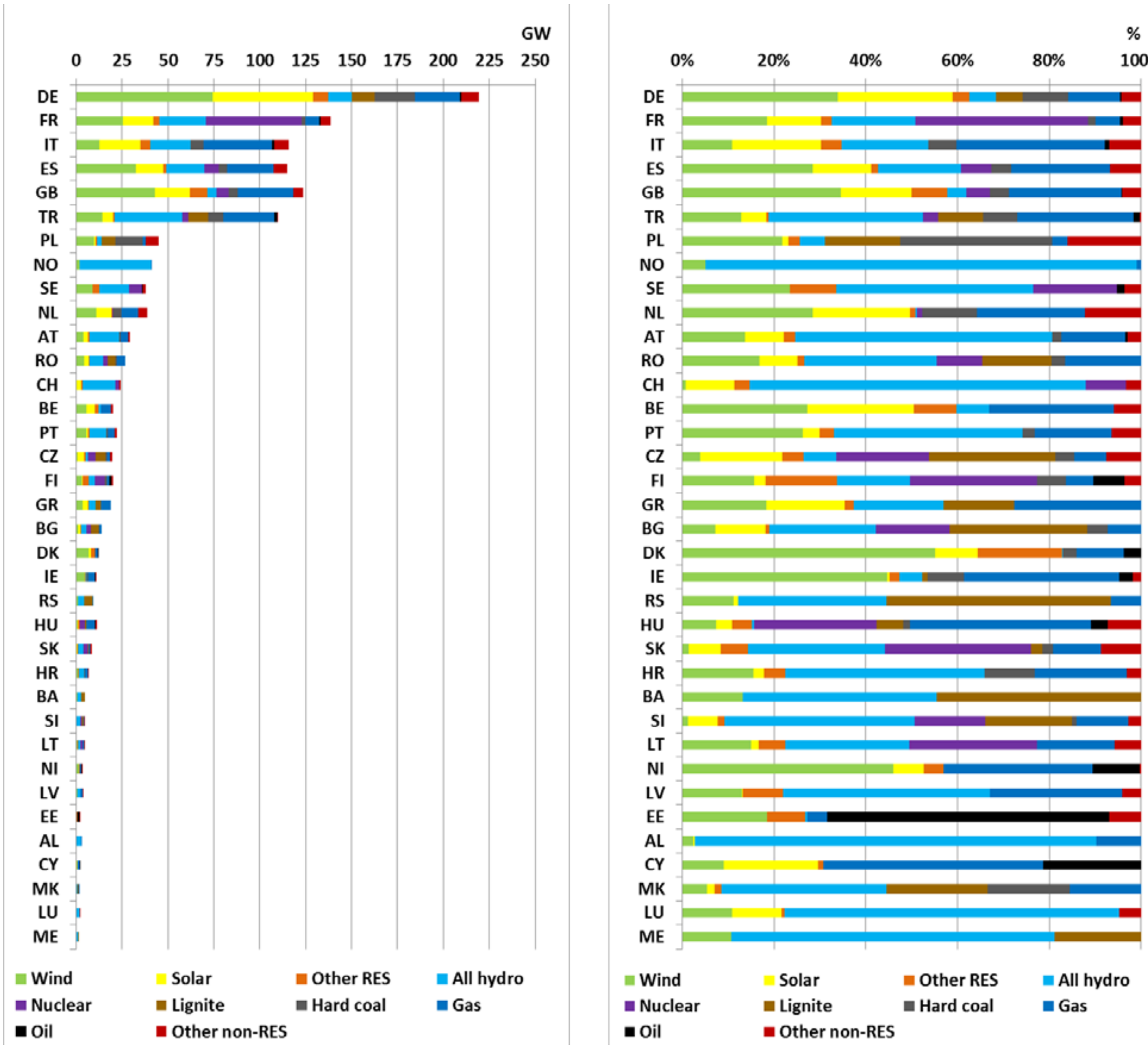

Figure 17 – Detailed Net Generating Capacity structure per country, year 2025

Figure 18 shows the differences in Net Generating Capacity between 2025 and 2020 at the whole Pan-European level. The increase in renewables between 2020 and 20205 is significant. Regarding fossil fuels, only the subcategory Gas, shows noticeable increase. The highest decrease of NGC is reported for Nuclear. Relative changes (in percentage) show that the biggest growth corresponds to both, Wind and Solar of an amount of 33%. On the other hand, the highest decrease refers to the 'Oil' subcategory (-32%), followed by Nuclear (-16%).

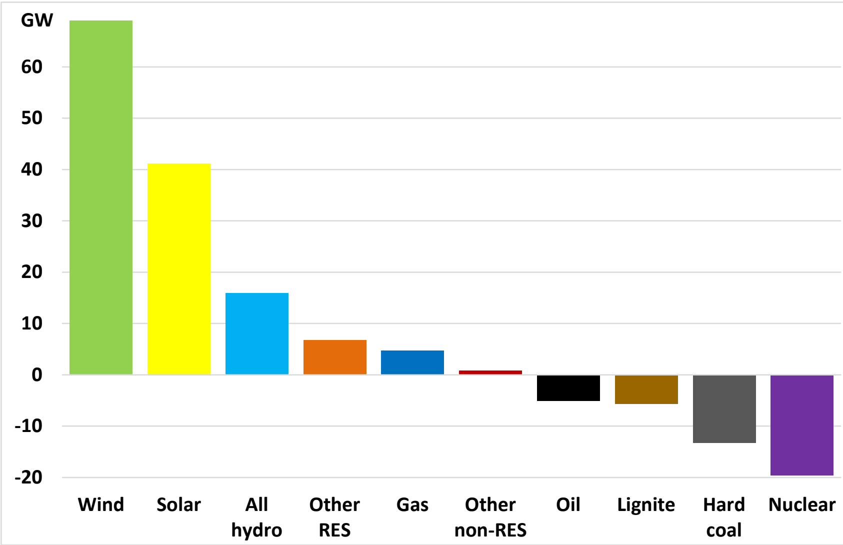

Figure 18 - Differences in Net Generating Capacity between 2025 and 2020, ENTSO-E level[11]

Figure 19 refers to the annual demand change between 2025 and 2020. The ENTSO-E annual demand increases yearly by 1.03% on average. The only country that reported an average yearly decrease of demand was Germany (-0.3%). On the other hand two countries forecasted a yearly demand increase higher than double of ENTSO-E average growth level: Cyprus (4.7%) and Turkey (5.7%).

	Demand
AL	0.1%
AT	0.3%
BA	1.5%
BE	0.0%
BG	0.6%
CH	0.0%
CY	4.7%
CZ	0.0%
DE	-0.3%
DK	1.6%
EE	1.1%
ES	0.8%
FI	0.6%
FR	0.1%
GB	0.6%
GR	1.9%
HR	1.6%
HU	0.9%
IE	1.8%
IT	1.2%
LT	0.8%
LU	0.5%
LV	2.1%
ME	1.4%
MK	2.1%
NI	0.5%
NL	0.4%
NO	0.9%
PL	1.6%
PT	1.5%
RO	1.1%
RS	0.6%
SE	0.0%
SI	2.0%
SK	1.5%
TR	5.7%
ENTSO-E in	1.03%

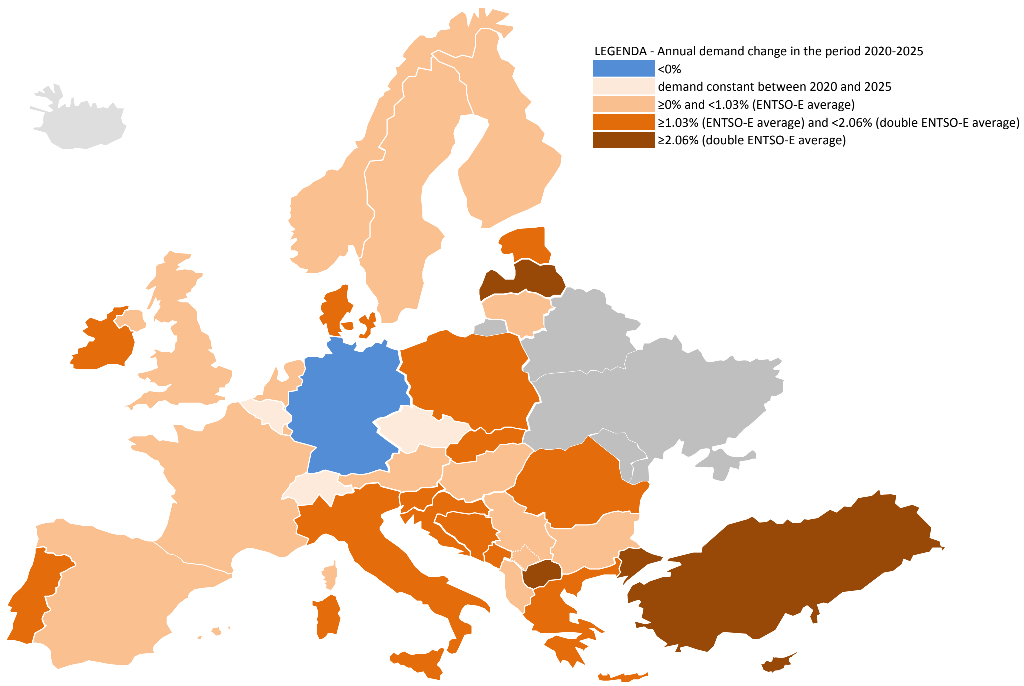

Figure 19 - Annual demand change in the period 2020-2025

11 'All Hydro' includes both, pump storage and renewable part of hydro. Therefore 'Other RES' does not include any renewable part of hydro, as was the case in SO&AF 2015 data structure.

4.2 Adequacy reference transfer capacities

Within the Mid-term Adequacy Forecast (MAF) 2016 a process for consolidation of the *Adequacy reference transfer capacities* values to be used for the adequacy simulations was setup. The target of the process was to ensure consistency with the TYNDP 2016 reference capacities, while providing a relevant set of transfer capacity values proper for adequacy risk assessments.

There are three different reasons, why to choose rather conservative (but still realistic) approach in providing these values for MAF 2016:

- Projects with the positive impact on the transfer capacities related to Scenario 2020 also include projects with date of commissioning not strictly before 2020 (see Regional Investment Plans of TYNDP 2016[12]).
- On top of that, every project carries certain level of uncertainty related to the ability to keep the process of realization in line with the scheduled time-line and date of the commissioning. Certain delays, months or even years, are sporadic and may cause a shift of commissioning beyond the focused time horizon.
- Moreover, system operation in practice brings also another reason to adopt even more conservative approach. Factors like maintenance and forced outages of power system elements, as well as influence of climate conditions (e.g. alternation of seasons), may lead to further decrease of transmittable capacity. At this moment the MAF methodology does not consider this explicitly, but this might be included in the further methodological improvements.

TSOs were also asked to propose values for **simultaneous importable / exportable capacities**. For adequacy simulations, these constraints should be considered since they might be imposed for some borders (e.g. in the flow based market coupling area) for reasons linked to internal grid stability and operational constraints.

[12] http://tyndp.entsoe.eu/

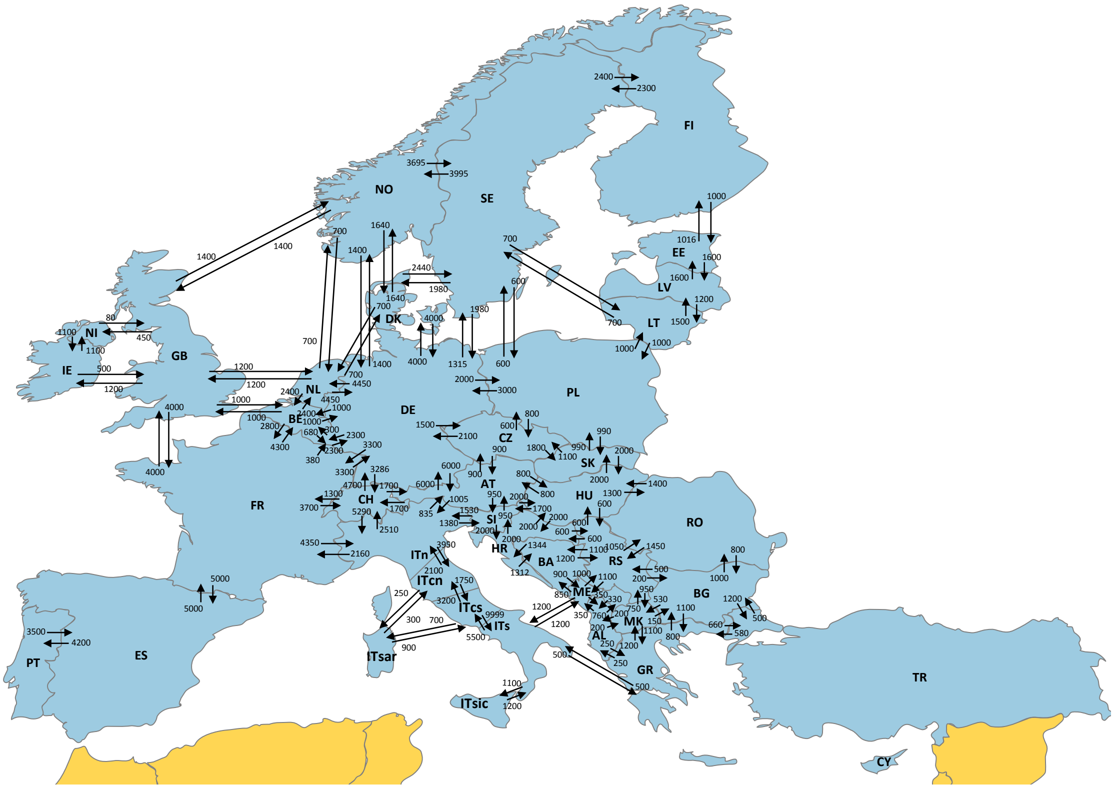

Figure 20 - 2025 adequacy reference capacity. See the MAF 2016 data package 'MAF2016 market modelling data.xlsx' for reference capacity data sets.

4.2.1 Force Outages for selected HVDC - Sensitivity II simulations

With respect to forced outages, these were simulated for power plants only but not for transmission lines or border profiles. Exceptions are the high-voltage direct current lines (HVDC). For the purpose of investigating the sensitivity of the system adequacy on the forced outage of HVDC lines, special simulations (*Sensitivity II*) were elaborated.

ENTSO-E report about the HVDC outages in the Nordics in year 2013 and CIGRE HVDC outage statistics that cover several years between 1990-2010 have been reviewed with the following conclusions:

• Unavailability rates for Baltic cable, Fenno-Skan 1, NorNed and Skagerrak 1&2 were higher in 2013 than in average (average based on CIGRE data)
• Unavailability rates for Fenno-Skan 2, Kontek, Skagerrak 3 and SwePol were about the same in 2013 than in average (average based on CIGRE data)
• Average unavailability rate for HVDV lines in the Nordics has been 6% and there has been about 6 outages/line/year (based on CIGRE statistics)

An unavailability rate for each HVDC interconnector of <u>6%</u> was decided as benchmark value.

It is noted that 6% is only the average value and for some interconnectors the rate has been higher (and for some a little bit lower), but assuming the same unavailability for each interconnector was pragmatic and would not overestimate the unavailability of HVDC links.

6% FOR was implemented in the following MAF interconnectors in the so-called **Sensitivity II** simulations (for the 'of which HVDC' part of the reported capacity in the table below):

Table 5 - Cross border boundaries where HVDC unavailability of 6% FOR has been implemented

Border/boundary	2020 base case MAF 2016	of which HVDC
BE-GB	**1000**	**1000**
DE-DKE	**1000**	**600**
DKE-DE	**1000**	**600**
DKE-DKW	**600**	**600**
DKW-DKE	**600**	**600**
DKW-NL	**700**	**700**
DKW-NO	**1640**	**1640**
DKW-SE	**740**	**740**
EE-FI	**1016**	**1016**
FI-EE	**1000**	**1000**
FI-SE	**2300**	**1350**
FR-GB	**2000**	**2000**
GB-BE	**1000**	**1000**
GB-FR	**2000**	**2000**
GB-IE	**500**	**500**
GB-NI	**450**	**450**
GB-NL	**1200**	**1200**
GR-ITS	**500**	**500**
IE-GB	**500**	**500**
ITcn-ITsar	**250**	**250**
ITsar-ITcn	**300**	**300**
ITS-GR	**500**	**500**
ITS-ME	**1200**	**1200**
ME-ITS	**1200**	**1200**
NL-DKW	**700**	**700**
NL-GB	**1200**	**1200**
NL-NO	**700**	**700**
NO-DKW	**1640**	**1640**
NO-NL	**700**	**700**
PL-SE	**300**	**300**
SE-DKW	**680**	**680**
SE-FI	**2400**	**1350**
SE-PL	**600**	**600**

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4.3 Hydro modelling: Hydro regions & dry - normal – wet conditions

A good probabilistic representation of the hydro generation system is required for the ENTSO-E geographical study area because there is significant amount of hydro installed capacity in 12 of the countries in Europe (Austria, Czech Republic, Finland, France, FYRO Macedonia, Italy, Norway, Portugal, Slovakia, Spain, Sweden and Switzerland). In the whole study area hydro also has a significant role since the total installed hydro capacity amounts 21.2% of the total installed capacity in 2020 (20.8% in 2025). Historical data has shown that the total annual hydro production can vary up to more than 20% between a dry and a wet year. In particular, in the Alpine region where weekly and seasonal pump-storages are dominant, the hydro electricity production in winter could significantly be reduced in a dry year. This could therefore result in a critical condition when the winter also happens to be cold.

Hydro generators have certain strategy according to which they make decisions on whether to generate or store the water. Hydro producers try to optimize their profit by balancing between water values, market price, hydro reserve levels and spilling. Water value can be understood as opportunity cost for water which is comparable to generation cost of other generation forms. If water value is lower than market price hydro generators will produce, otherwise they will save the water for future.

Multiple Hydro regimes and Regional approach

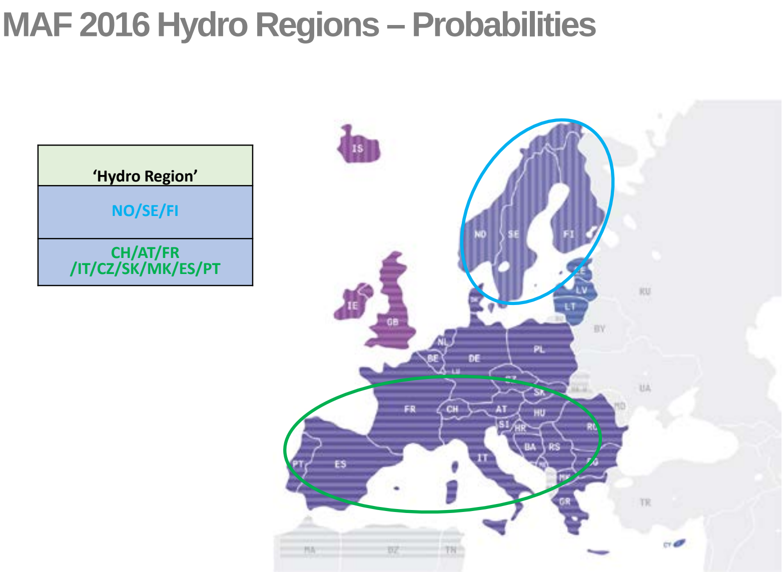
The definition of suitable hydro profiles which can be used as a common approach for all countries in 2020 and 2025 studies (taking into account the availability of data) is required. By applying statistical analyses three distinctive hydro regimes for each country are derived: “dry”, “wet” and “normal”. To facilitate the probabilistic methodology, each of these profiles has to be associated to its corresponding probability, which represents the likelihood/frequency of its occurrence. Each of these regimes contains the weekly values for RoR (Run-of-River), reservoir production (storage, pumped storage, and swell power plants) and natural inflow for reservoir.

Three sets of data, each of them corresponding to a single hydrological “normal” year (e.g. closest hydrological year to the 50% percentile), “(most-) dry” year and “(most-) wet” year were prepared by TSO.

Considering the geographical proximity of countries, it is expected that their hydrological conditions should be closely correlated, i.e. when there is a dry year in Switzerland, it should also be dry in Austria and France, and vice versa.

Ideally the hydrological data from all hydro countries within a region should be used in order to work out a regional correlation. In practice there are some constraints. For instance, derivation of the PLEF region hydrological years were mostly based on the Swiss historical hydrological data, which include more than 10 years of inflow, river flow and hydro production data. While these hydrological years for other hydro countries were checked and verified their associated probability of occurrence was derived based on the Swiss historical river flow only (80 years). This was due to limited availability of these data in the region. The model can be and should be improved when more hydrological data from these countries become available.

The Pan-European perimeter was divided in two regions regarding hydrological conditions ensuring that dry-average-wet hydro conditions are correlated among the countries within regions. The decision to harmonize the probabilities of countries into hydro regions is motivated by a pragmatic need only (so ease the MC procedure); as a result Monte Carlo analysis can investigate, for each yearly run, a composition of 9 hydro conditions. The same applies to the aggregation of sub-regions AT-FR-CH (PLEF hydro), IT, CZ & SK, MK and ES & PT with the aim of reducing the total number of hydro conditions to be examined and it is not an outcome of a validation process to verify effective correlation of hydro conditions among the countries.



Hydro Data Probabilities[13]	Dry	Normal	Wet
Region	Probability [%]	Probability [%]	Probability [%]
CH/AT/FR /IT/CZ/SK/MK/ES/PT	10	80	10
NO/SE/FI	18	50	32

Figure 21 - Hydro Regions and corresponding probabilities

Italy specifics

In Italy, the majority of hydro plants are located in the north, so it is likely that they are correlated to the PLEF region (Austria, Belgium, France, Germany, Luxemburg, Switzerland and The Netherlands) hydro production. It is important to highlight that big power plants are situated also in the south and in the main islands.

As in PLEF study, the Swiss hydrological data, i.e. the amount of water expressed in MWh, were used for the derivation of the hydrological years for Austria, France and Switzerland. Analyses were conducted to work out the correlation between the Swiss hydro production and these Swiss hydrological data. It was found that there is a correlation but not very high (between 0.6 and 0.7). For Italy only historical hydro production data were available. When analysing the hydro production data between Switzerland and Italy the results did not seem to show significant correlation. It is depicted in the following graph.

[13] Probabilities represent rough estimates as there is a distinction between percentile (on the value) on hydrological year selection and the associated probability of occurrence for the Monte-Carlo simulations.

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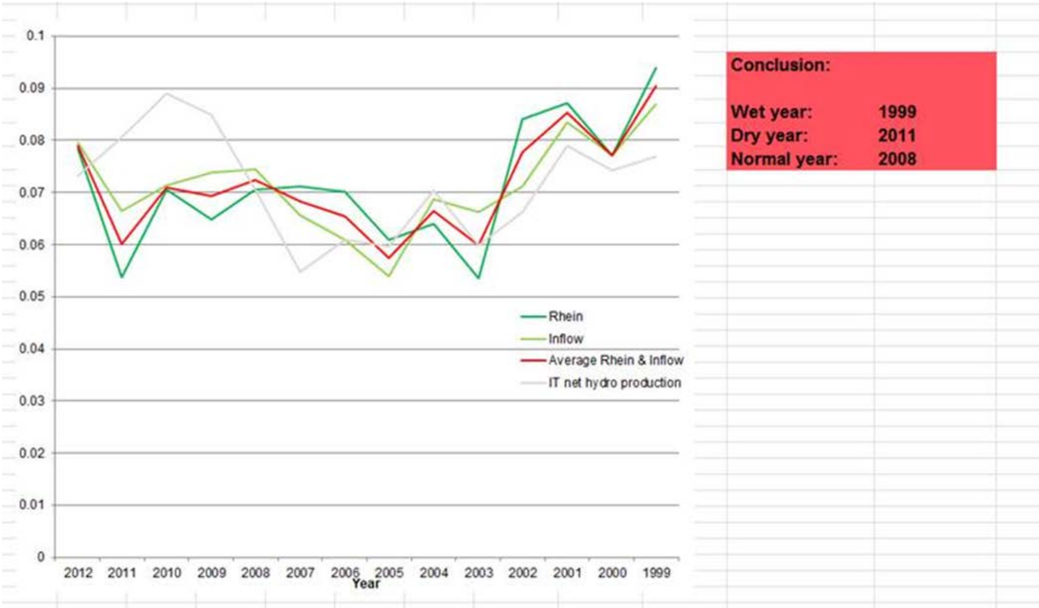

Figure 22 – Switzerland and Italy historical hydro production (Note that the years are reversed in the x-axis)

The result is inconclusive: The hydro production in IT, a non-hydro dominated country, is not strictly related to the amount of water, in fact the overall correlation is only about 0.46 with the Swiss data. But indeed there was a high correlation till year 2008: If only the data for years 1999 to 2008 were used the correlation jumps up to 0.76.

Nordic countries (NO/SE/FI) specifics

Hydro generation has a major role in Nordic countries. In average, total hydro generation in Nordic countries is about 200 TWh annually. However, there can be huge differences in annual generation depending on the precipitation.

Hydro data preparation under PEMMDB format is rather complex for the Nordics. Nordic TSOs typically check the data quality before data delivery to ENTSO-E by optimize/run simulations to produce a representative reservoir trajectory for average, dry or wet year. In dry years reservoirs might not necessarily get to the same yearly end, as typically it is not anticipated to have 2 consecutive dry years and there is a chance to refill the reservoirs.

MAF 2016 experts from the Nordics agreed with Nordic TSOs to prepare a dry - wet Nordic data sets by performing BID modelling runs. This data was checked and agreed by the Nordic TSOs.

Similar to other hydro-storage operators, the Nordic hydro generators have certain strategy according to which they make decisions on whether to generate or store the water. Hydro producers try to optimize their profit by balancing between water values, market price, hydro reserve levels and spilling. Water value can be understood as opportunity cost for water which is comparable to generation cost of other generation forms. If water value is lower than market price hydro generators will produce, otherwise they will save the water for future.

Electricity market models that are used in Nordic countries (BID, EMPS) are linear optimization models that have two parts, a strategy part and an optimization part. First, the strategy component calculates the water values for hydro reservoirs. After that the optimization component optimizes the generation in the whole market area. If a market model is not able to optimize hydro generation according to the strategy that producers use, the results for Nordic countries will be unrealistic. If hydro generation is not allocated optimally, it may result in power adequacy issues and unrealistic high LOLE values. For this reason hydro strategy for Nordic countries should always be calculated with the models that are able to simulate the hydro strategy that Nordic producers typically use as guidance in the market positioning. Because water values cannot be transferred between the models, hydro reservoir curves for Nordics could be extracted from the Nordic TSO model of choice (in MAF 2016 case S4 = BID) and then utilized in other models as guidance. This would result in hydro allocation that is consistent with the Nordic expectations at the yearly level.

The following figure describes the process.

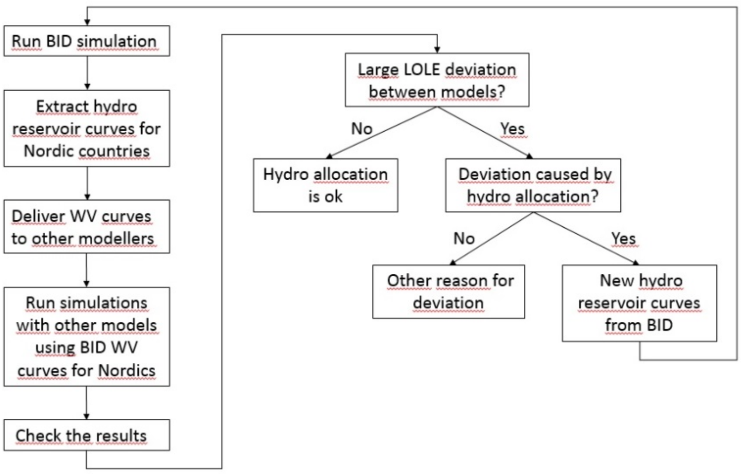

Figure 23 - Iterative process to prepare hydro data.

Furthermore, when performing the probabilistic simulations for the Nordic countries, the hydro probabilities are correlated with the climatic year choice as follows.

Table 6 - Correlation among hydrology in the Nordic countries and PECD.

PECD yr	HYDRO set	P% wet	P% normal	P% dry
2000	wet	1	0	0
2001	normal	0	1	0
2002	dry/normal	0	0.5	0.5
2003	dry	0	0	1
2004	normal	0	1	0
2005	wet	1	0	0
2006	normal	0	1	0
2007	wet	1	0	0
2008	normal	0	1	0
2009	normal	0	1	0

2010	dry	0	0	1
2011	wet	1	0	0
2012	normal/wet	0.5	0.5	0
2013	normal	0	1	0
	average	**0.321429**	**0.5**	**0.178571**

Iberian Peninsula (ES/PT) specifics

A strong hydrological correlation exists between Iberian countries - Spain and Portugal - due to their geographic proximity, therefore same “hydro years” (regimes) concerning dry, normal and wet conditions were provided for 2020 and 2025 as follows:

- Dry: 2005;
- Normal: 2004;
- Wet: 2003.

For pragmatic reasons it was assumed that there is a strong correlation of hydrologic behavior among Iberian countries and adjacent regions, namely PLEF. However no statistical evidences or analysis were used to support this option. The same applies to individual probability of occurrence of the three different hydro regimes, whereas the same plausible 10%-80%-10% to Dry-Normal-Wet conditions were used as for PLEF.

4.4 Exchanges with non-explicitly simulated countries

From the point of view of the adequacy assessment, the perimeter of the study and the assumptions about how to model the exchanges at the borders between simulated countries and non-simulated countries are an important element, which can notably affect the adequacy indices, especially in case of importing flows (non-ENTSO-E→ENTSO-E). In MAF simulations, all the tools have considered as an input to the models, predefined exchanges with the borders of the ENTSO-E perimeter.

Exchanges with non-ENTSO-E countries, as well as exchanges within the ENTSO-E region present the commercial exchanges. As PEMMDB database does not contain data regarding the generation portfolio, demand and other parameters necessary to model the countries of the non-ENTSO-E region, it is not possible to include these countries into the adequacy assessment market model and model the exchanges with these countries in the standard way. For this reason the exchanges are not the output of the simulation driven by market, but are the input to the model in the form of annual hourly data series defined by TSOs of those ENTSO-E countries, which expect the exchanges on the borders with their non-ENTSO-E neighbors in particular time horizon.

How the hourly data series were built

If the required exchanges are related to the border, which is in operation on the present already, the hourly data series were built based on the real operation, using information about the real commercial flows on that border as a base. It was needed to keep up the particularity of the real commercial exchanges like the fluctuation of flows caused by the alternation of seasons (winter/summer), changing of the load within a day (peak/off-peak), switching off the related systems/equipment for the maintenance purpose/outages and other. The typical behavior of the real exchanges was kept even if some development projects with influence on these exchanges are expected to be realized.

Some countries interconnected via non ENTSO-E system (e.g. Slovakia-Hungary-Romania via Ukraine; Estonia-Latvia via Russia) may affect each other's exchanges. If they do, TSO of these countries cooperated during the process of building the exchanges hourly data series to keep the correlation of these exchanges.

If the required exchanges are related to a border, which does not exist on the present but will exist due to a future interconnection project, it is not possible to build the exchanges based on the historical operation in practice, and it was up to the TSO to build the exchanges profiles based on their best estimates. However, it is important to keep in mind that the profile should not gain the shape of a line with the constant power in all year long, unless the exchanges of such a shape are really expected. This may be in case of the DC connection, but not the AC connection connecting two meshed systems, where the constant exchanges will typically not occur. TSOs used their own market simulation tool to build the exchanges by internal market simulations.

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5 Detailed Model Results

In this chapter the detailed results obtained from adequacy analysis carried out with different tools are finally presented. The comparison of the results from different tools requires extra effort for the reader: this is the price to pay in order to have reliable results benchmarked by different tools. In order to assure that the same use of data is made by different tools several steps have been performed to compare the results.

Table 7 - summarizes all the steps performed for 2020. Similar steps have been performed for 2025

<table>
<tr><th>Step</th><th>NTC</th><th>FOR Therm Units</th><th>Demand</th><th>RES profiles</th><th>Hydro</th><th>Operational Reserves contribute to adequacy: Yes/No?</th><th>FOR HVDC</th></tr>
<tr><td rowspan="2">S0</td><td>Isolated case (all NTC=0)</td><td rowspan="2">no FOR</td><td rowspan="3">2020 load under ‘normal climatic condition’ rescaled using 2010 temperature</td><td rowspan="3">PECD 1.0 (year 2010)</td><td rowspan="3">All dry</td><td>yes</td><td>no</td></tr>
<tr><td rowspan="6">Ref NTC + simultaneous imp/exp</td><td>yes</td><td>no</td></tr>
<tr><td>S1</td><td rowspan="5">MC drawing parameter</td><td>yes</td><td>no</td></tr>
<tr><td>S2 (Sensitivity I)</td><td rowspan="4">2020 load under ‘normal climatic condition’ rescaled with PECD temperature (2000-2013)</td><td rowspan="4">PECD 1.0 (2000-2013)</td><td rowspan="4">Dry-Normal -Wet</td><td>yes</td><td>no</td></tr>
<tr><td>S3 (Base Case)</td><td>no</td><td>no</td></tr>
<tr><td>S4 (or s2b)</td><td>yes</td><td>yes (only Nordics)</td></tr>
<tr><td>S5 (Sensitivity II)</td><td>yes</td><td>yes (all HVDC)</td></tr>
</table>

The first steps are mainly used for calibration purpose. In the following pages we present in detail the results of the following steps:

- **S3 – Base Case**: this simulation without operational reserve gives a more pessimistic view, but is important in order to detect on time possible adequacy problems (since operational reserves are subtracted and not used to compensate a possible deficit of generation capacity); that case has been chosen as “reference case” also taking into account the necessary assumptions, common to all the tools used, of perfect foresight and forecast in Day-Ahead markets (error in forecast load and renewable are not simulated);
- **S2 – Sensitivity I**: Operational reserves contributing to adequacy: in this simulation the reserves are NOT reduced from the total installed capacity. This simulation gives a more optimistic view since the reserves will be used for adequacy purposes.

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- **S5 – Sensitivity II:** same of S2 – Sensitivity I complemented by unavailability of cross-border capacity due to forced outages of selected HVDC interconnectors.

5.1 2020

Note that in this chapter **S#** (#3,#2,#5) denotes **Base Case**, **Sensitivity-I** or **Sensitivity–II** simulations. Simulators tools are rather referred as **Voluntary Parties VP#** (#2 – ANTARES, #4 – BID, #5 – PLEXOS, #6 – GRARE) in this chapter.

5.1.1 2020 – S3 or "Base Case"

The figure below shows the average ENS (expressed in MWh) for all the Pan EU countries analyzed (each country is represented in the model with 1 market node, except Denmark, Italy and Luxembourg which are split respectively in 2, 6 and 3 different market nodes).

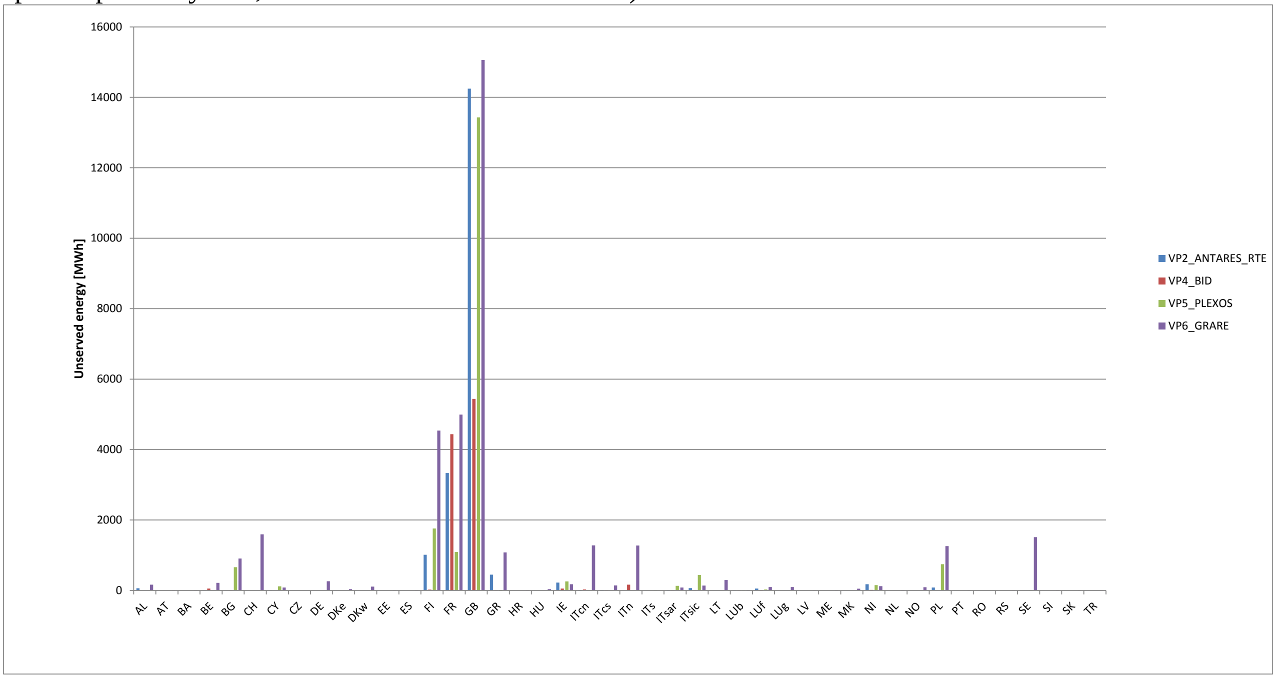

Figure 24 – Energy Non Served (ENS) distribution (Base case 2020)

The average, although useful and easily understandable, is not representative of the most extreme conditions which typically will push the power system to stress situation (e.g. situations of scarcity). Decision makers would like to know if the system is resistant when critical situations happen and what are the limits of the system. The distance between the average, calculated with regards to the different number of years simulated by the different tools, and the most extreme ENS in the sample simulated is graphically represented in the figure below (difference between the horizontal lines and the blue spikes). Figures of Average and P95 are given in the table below also:

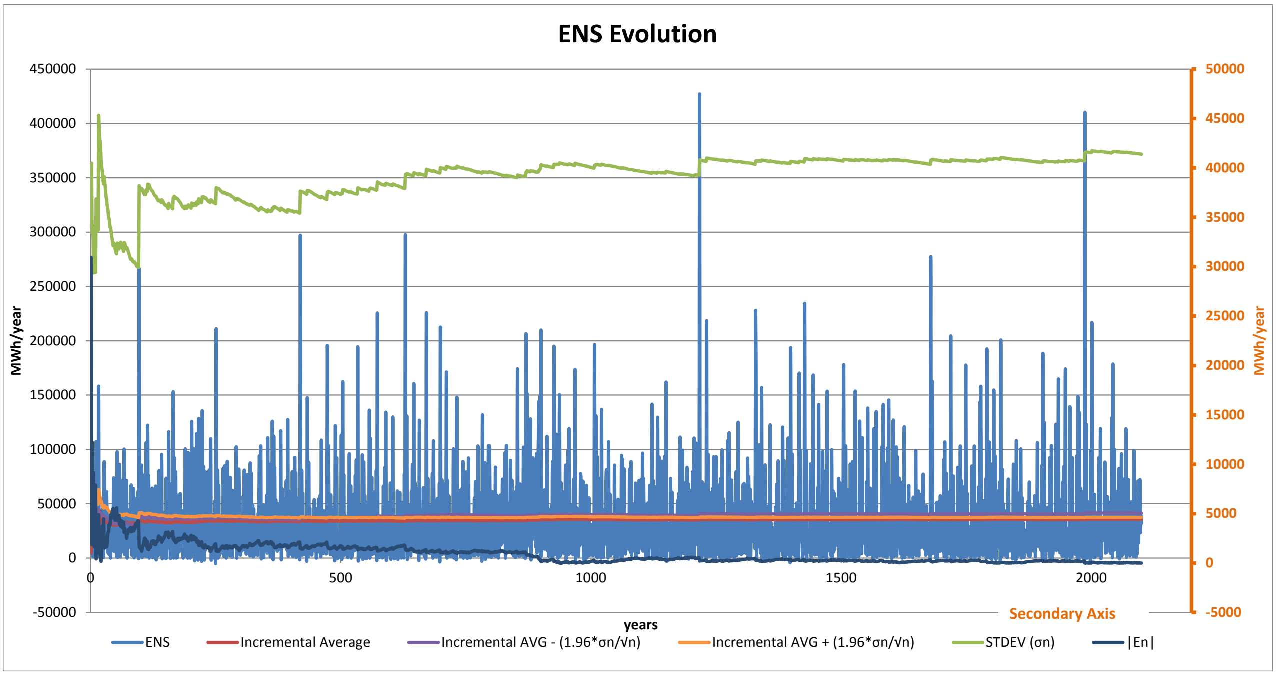

Figure 25 – Example of convergence on all the MC years (Base Case - VP6)

Table 8 – Average and P95 for ENS from all VPs (Base case 2020)

ENS [MWh]	VP2		VP4		VP5		VP6	
	average	P95	average	P95	average	P95	average	P95
AL	64	458	0	0	0	0	163	885
AT	0	0	0	0	0	0	1	0
BA	0	0	0	0	0	0	0	0
BE	1	0	55	340	0	0	217	1242
BG	0	0	4	0	662	2761	905	4178
CH	0	0	0	0	0	0	1594	6759
CY	1	0	0	0	118	655	86	89
CZ	0	0	0	0	0	0	0	0
DE	0	0	0	0	0	0	261	1575
DKe	0	0	0	0	0	0	38	251
DKw	0	0	0	0	0	0	110	734
EE	0	0	0	0	0	0	2	0
ES	0	0	0	0	0	0	2	0
FI	1014	4924	23	200	1760	5726	4540	21364
FR	3332	14214	4439	15357	1093	4906	4991	21387
GB	14247	46946	5440	23310	13430	43612	15061	58558
GR	448	2572	0	0	11	0	1081	3276
HR	0	0	0	0	0	0	1	0
HU	0	0	0	0	0	0	39	0
IE	224	1118	55	325	258	1217	179	923
ITcn	10	0	31	250	3	0	1281	6298
ITcs	9	0	0	0	0	0	143	1131
ITn	0	0	166	1391	0	0	1275	7162
ITs	0	0	0	0	4	0	0	0
ITsar	8	0	0	0	131	1021	84	472
ITsic	67	203	0	0	439	2628	140	663
LT	0	0	0	0	0	0	295	2088
LUb	3	0	0	1	3	24	8	42
LUf	54	314	7	25	29	193	96	413
LUg	0	0	0	0	0	0	96	701
LV	0	0	0	0	0	0	4	2
ME	0	0	0	0	0	0	2	2
MK	0	0	0	0	0	0	52	158
NI	179	870	17	103	154	972	123	607
NL	0	0	0	0	0	0	7	0
NO	0	0	0	0	0	0	92	546
PL	86	0	0	0	745	4275	1260	5306
PT	0	0	0	0	0	0	0	1
RO	0	0	0	0	0	0	0	0
RS	0	0	0	0	0	0	0	0
SE	0	0	0	0	5	0	1516	11388
SI	0	0	0	0	0	0	0	0
SK	0	0	0	0	0	0	0	0
TR	0	0	0	0	0	0	1	0

To give a *dimensional* indication of the risk of security of supply (to avoid underlining only big systems) we have compared the ENS with yearly energy demand in Figure 9.

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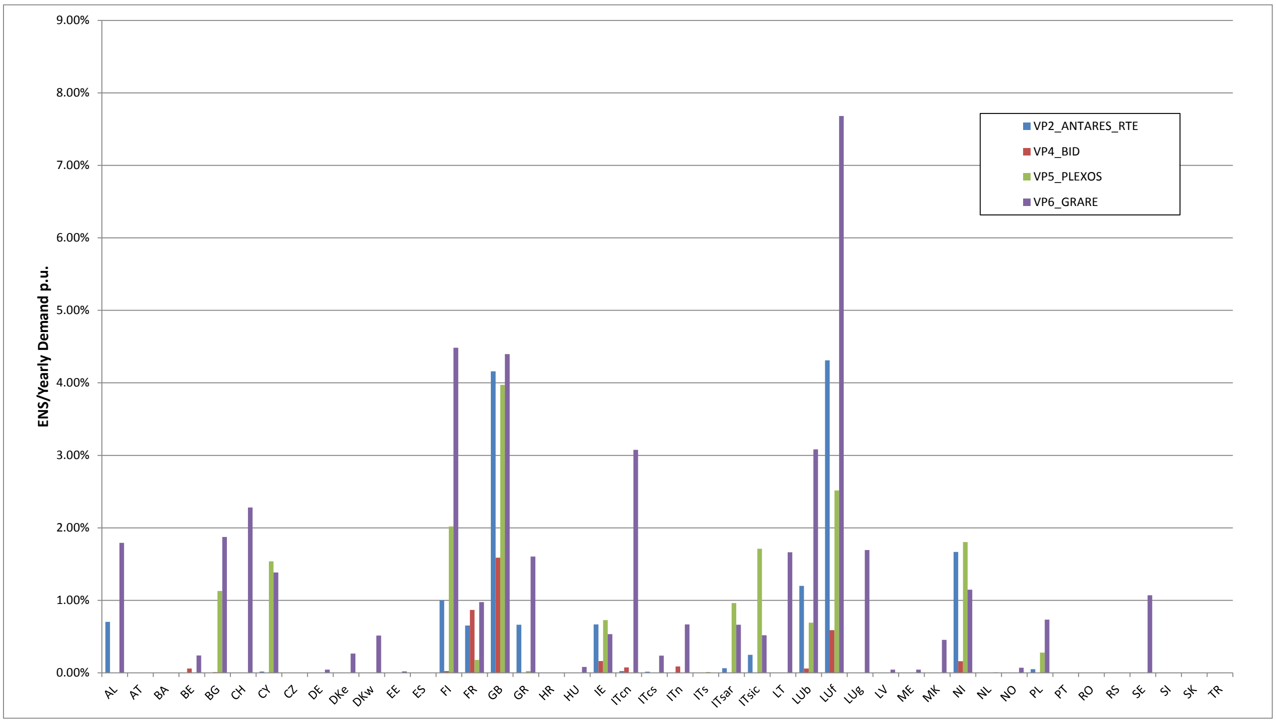

Figure 26 - ENS divided per yearly demand (Base case 2020)

Below the comparison of the average LOLE calculated by the different models is shown (see figure and table below).

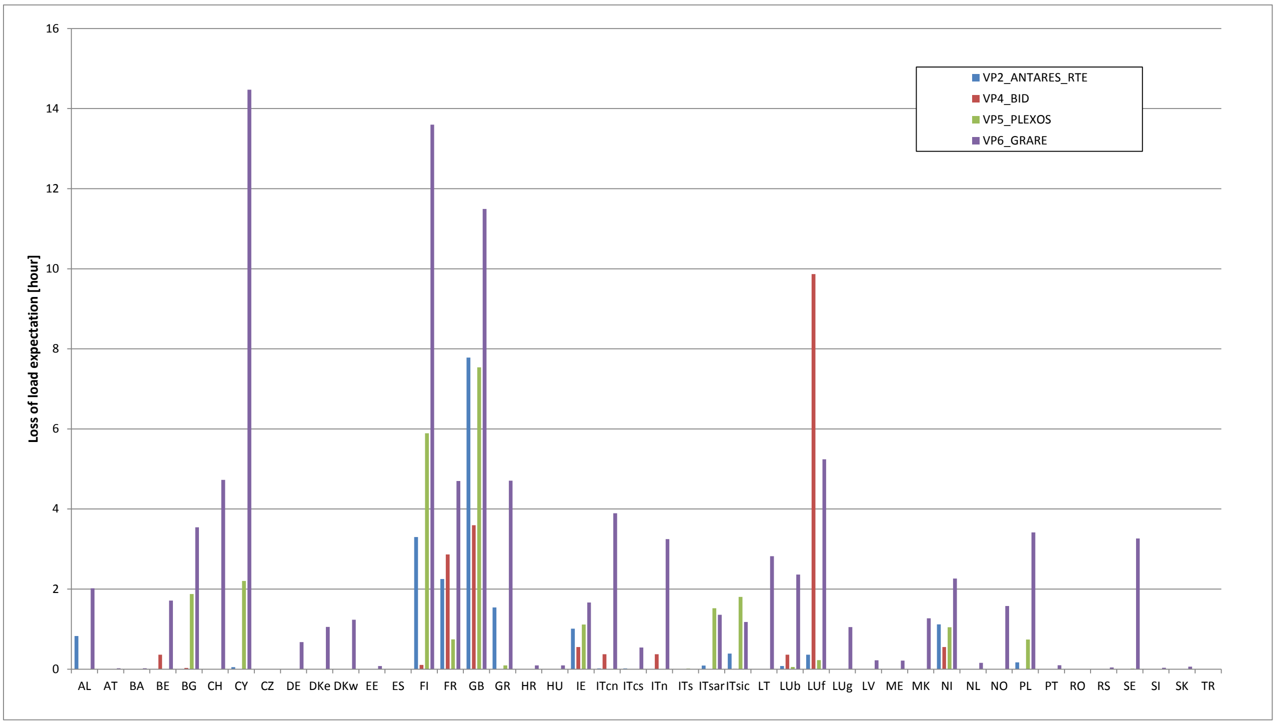

Figure 27 Loss of Load Expectation (LOLE) distribution (Base Case 2020)

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Table 9 – Average and P95 for LOLE from all VPs (Base case 2020)

LOLE [hours]	VP2		VP4		VP5		VP6	
	average	P95	average	P95	average	P95	average	P95
AL	1.000	3.000	0.000	0.000	0.000	0.000	2.000	10.000
AT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
BA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
BE	0.000	0.000	0.361	2.249	0.000	0.000	2.000	8.000
BG	0.000	0.000	0.030	0.030	2.000	11.000	4.000	18.000
CH	0.000	0.000	0.000	0.000	0.000	0.000	5.000	20.000
CY	0.000	0.000	0.000	0.000	2.000	15.000	14.000	26.000
CZ	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DE	0.000	0.000	0.000	0.000	0.000	0.000	1.000	6.000
DKe	0.000	0.000	0.000	0.000	0.000	0.000	1.000	8.000
DKw	0.000	0.000	0.000	0.000	0.000	0.000	1.000	8.000
EE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
ES	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FI	3.000	24.000	0.108	0.929	6.000	29.000	14.000	54.000
FR	2.000	10.000	2.866	9.917	1.000	4.000	5.000	20.000
GB	8.000	19.000	3.594	15.402	8.000	19.000	11.000	40.000
GR	2.000	7.000	0.002	0.015	0.000	0.000	5.000	20.000
HR	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
HU	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
IE	1.000	6.000	0.555	3.305	1.000	5.000	2.000	8.000
ITcn	0.000	0.000	0.374	3.040	0.000	0.000	4.000	18.000
ITcs	0.000	0.000	0.001	0.010	0.000	0.000	1.000	4.000
ITn	0.000	0.000	0.374	3.137	0.000	0.000	3.000	16.000
ITs	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
ITsar	0.000	0.000	0.003	0.000	2.000	12.000	1.000	6.000
ITsic	0.000	1.000	0.007	0.000	2.000	12.000	1.000	8.000
LT	0.000	0.000	0.000	0.000	0.000	0.000	3.000	20.000
LUb	0.000	0.000	0.361	2.265	0.000	0.000	2.000	10.000
LUf	0.000	2.000	9.866	33.576	0.000	1.000	5.000	22.000
LUg	0.000	0.000	0.000	0.000	0.000	0.000	1.000	8.000
LV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.000
ME	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.000
MK	0.000	0.000	0.000	0.000	0.000	0.000	1.000	4.000
NI	1.000	3.000	0.555	3.334	1.000	5.000	2.000	12.000
NL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NO	0.000	0.000	0.000	0.000	0.000	0.000	2.000	12.000
PL	0.000	0.000	0.000	0.000	1.000	6.000	3.000	24.000
PT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.000
RO	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
RS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SE	0.000	0.000	0.000	0.000	0.000	0.000	3.000	24.000
SI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SK	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TR	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

– **Sensitivity of results between FR, CH, IT**: The different runs (VP2, 4, 5, 6) performed exploit the interrelation between hydro power dispatch, pumped storage flexibility and availability of thermal production. More constrained simulations imposing non perfect foresight on the outages of thermal power plants in relation to hydro scheduling does not result in the same level of optimized use of hydro flexibility in CH, and FR resulting in the higher values of ENS observed for FR and these are correlated with the ENS values observed for CH, and IT, since they rely on imports form FR in scarcity situations.

Table 10 – Monte Carlo years simulated and confidence interval obtained by different Simulators (Base case 2020)

Tool	MC years	Confidence interval [%]
ANTARES	1120	6.55%
BID	1600	6.00%
PLEXOS	280	12.36%
GRARE	2100	4.96%

5.1.2 2020 – S2 "Sensitivity – I"

These results provide an outlook of the main adequacy problems for a 2020 scenario assuming operational reserves contributing to adequacy on top of day-ahead (D-1) considerations. The contribution of operational reserves improves the adequacy situation with respect to the results provided in the Base Case.

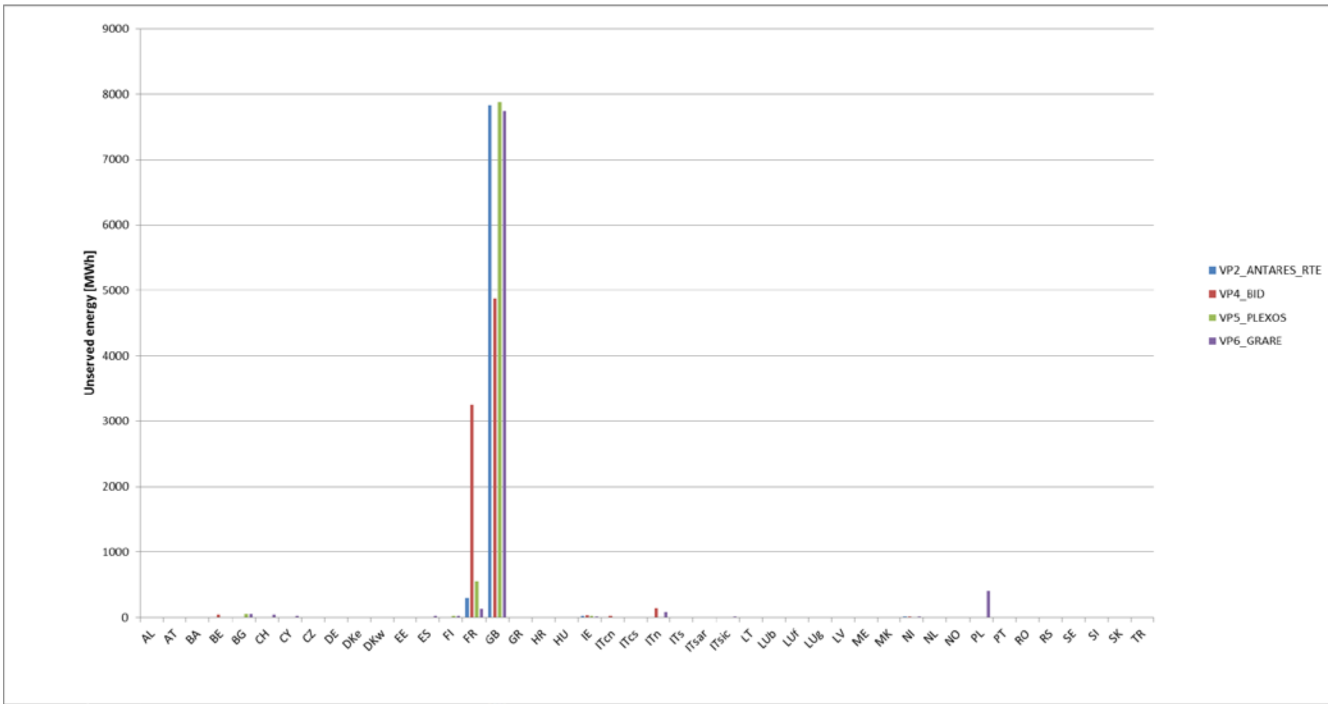

Figure 28 ENS 2020 Sensitivity I

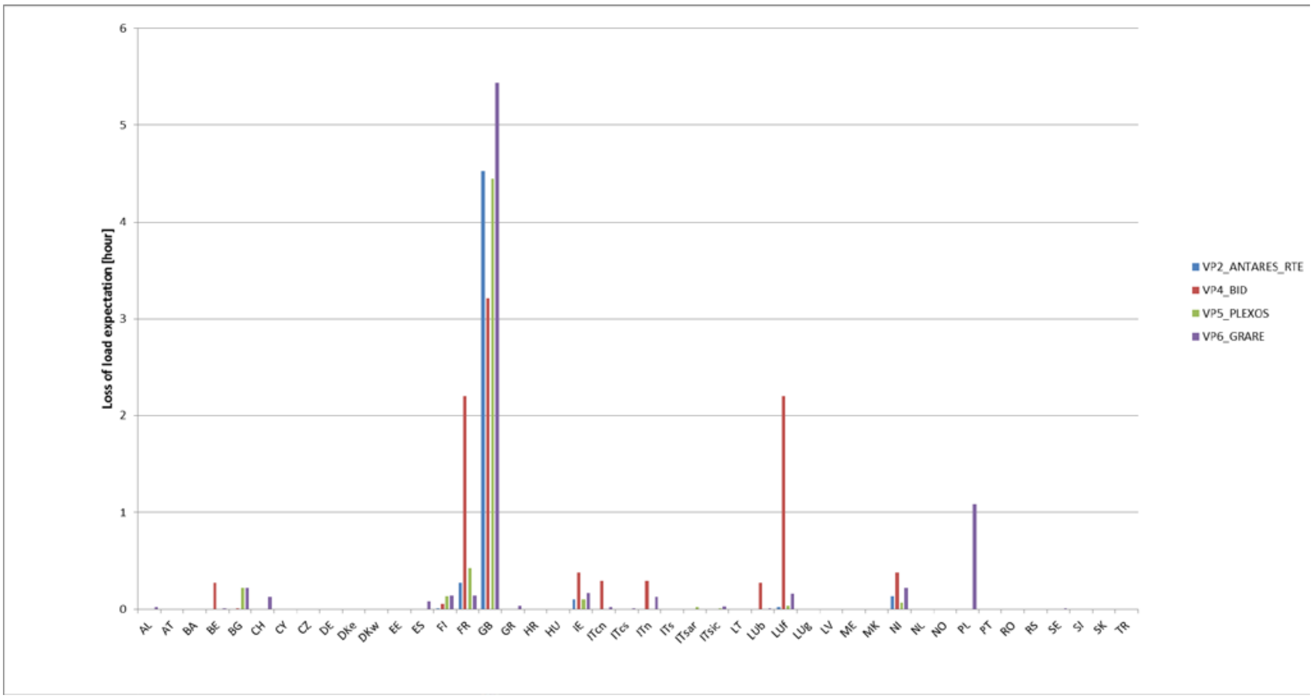

Figure 29 LOLE 2020 Sensitivity I. (LOLE of CY= 16 h not shown for visibility since ENS is just 30 MW)

5.1.3 2020 – S5 “Sensitivity – II”

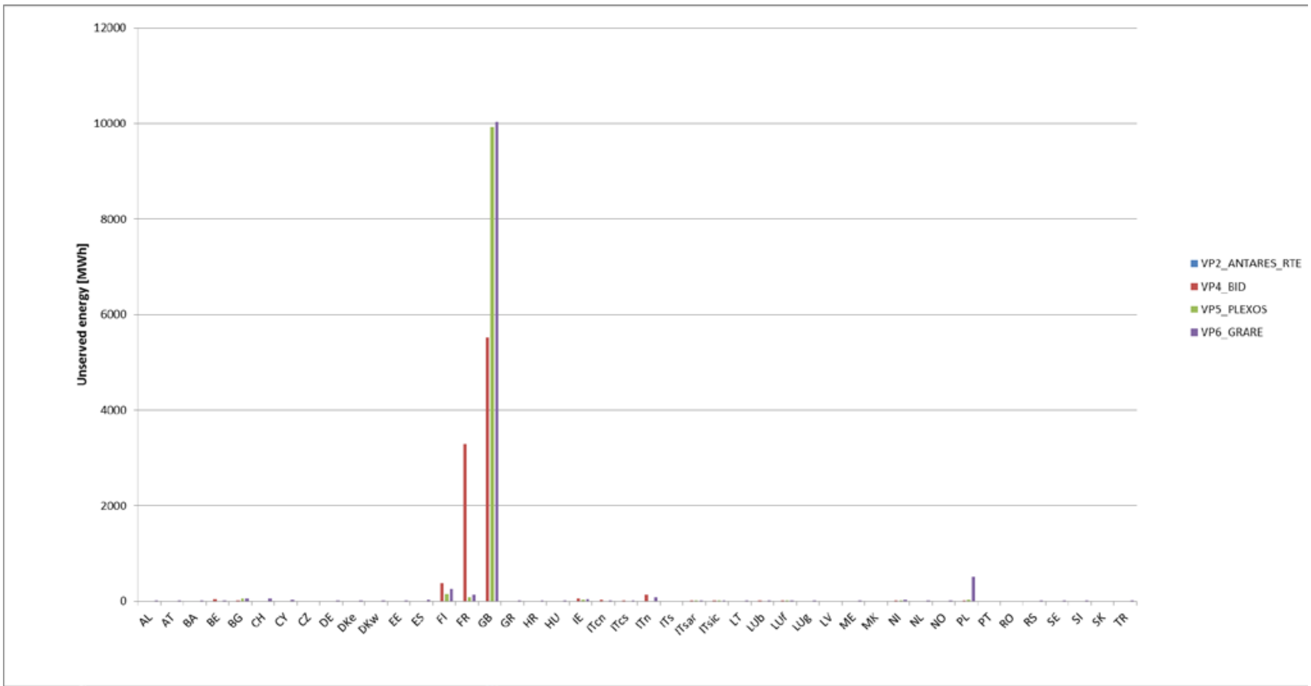

Figure 30 ENS 2020 Sensitivity II

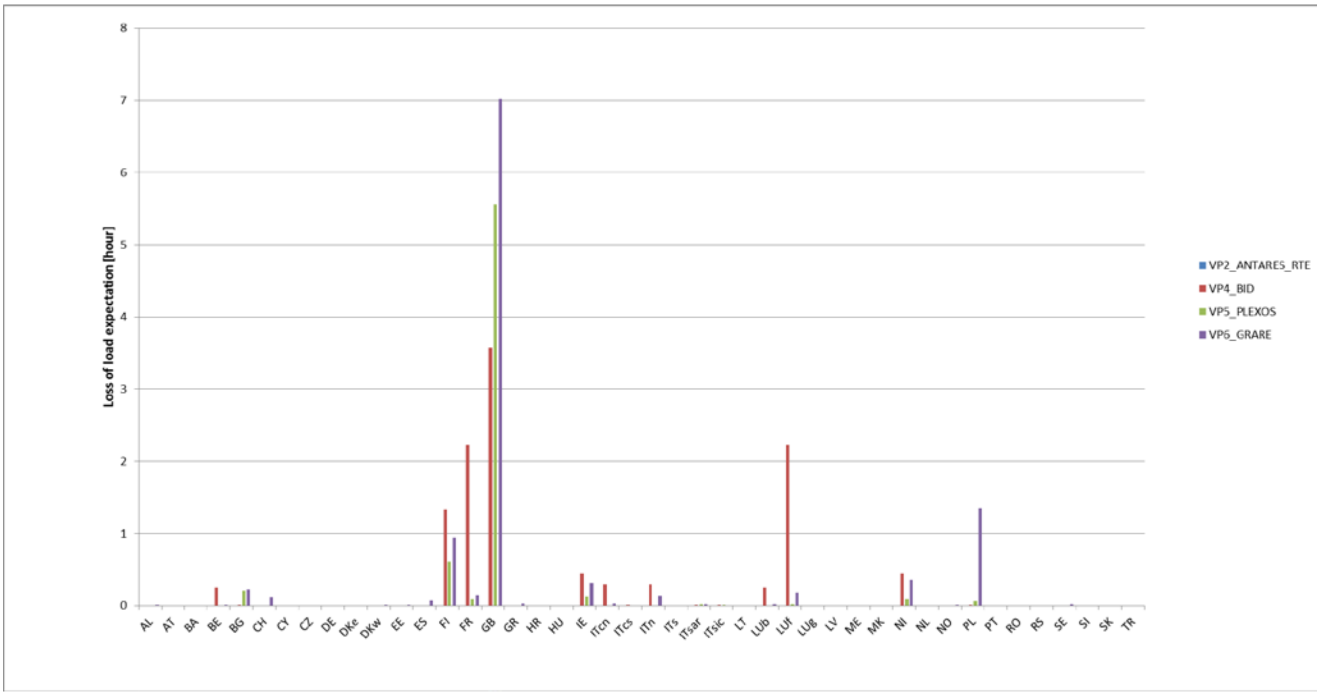

Figure 31 LOLE 2020 Sensitivity II. (LOLE of CY= 16 h not shown for visibility since ENS is just 30 MW)

5.2 2025

An increase in the occurrence of adequacy problems is observed in the 2025 scenario compared to the 2020 scenario due to the general increase in the load (Figure 19) and the change in the generation mix where thermal units are substituted from an increase in renewable productions (Figure 18).

Despite the different level of Monte Carlo samples simulated by different tools a good level of convergence has been achieved by all of them. The apparent ‘misalignment’ in the results has been extensively studied and the explanation is the following:

- The differences of the results between tools do not strive from a lack of robustness of the results of (one or several of the) tools but the different optimization logic used by the different tools. We consider import to highlight the slight sensitivity of the results to these modelling features, *with all data and other assumptions aligned between the tools*. In particular these differences in the results should be understood as a sensitivity in itself, which indicate the importance of flexible generation, in this case hydro power mainly, to react against both variability due to RES but also unavailability of thermal generation due to force outages.
- The higher values of ENS/LOLE reported by **VP6 – GRARE** is related to the fact that this tool, differently from the other, does not employ a different pumping/generating regime for different Forced Outage Rate patterns. Hydro optimization assumes to have only the knowledge of forced outages rates (FOR) of thermal units applied as a reduction of production capability and not depending on Monte Carlo sampling.
- The lower values than of ENS/LOLE reported from **VP2 – ANTARES** and **VP4 – BID** are related to the fact that a different hydro optimization is considering each MC year considering a perfect forecast knowledge of forced outages (FOR) of thermal units. This perfect foresight information is provided to the hydro optimization so hydro power optimizes its schedule to minimize adequacy problems.

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5.2.1 2025 – S3 or “Base Case”

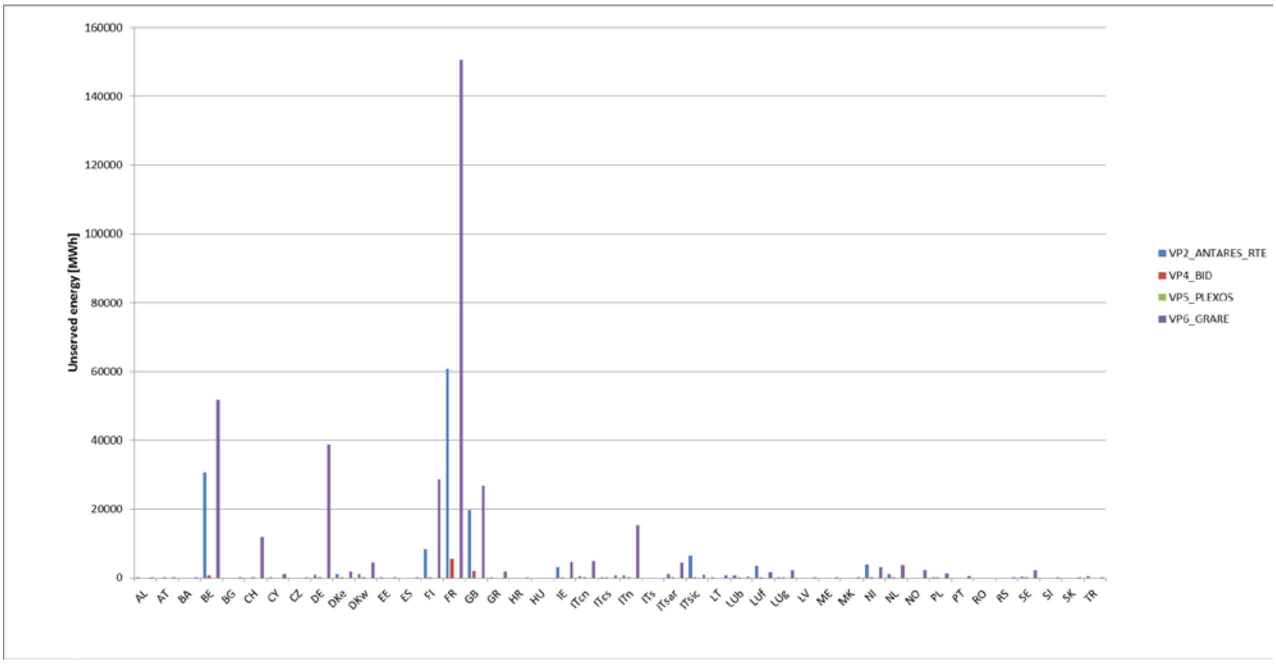

Figure 32 2025 ENS Base Case

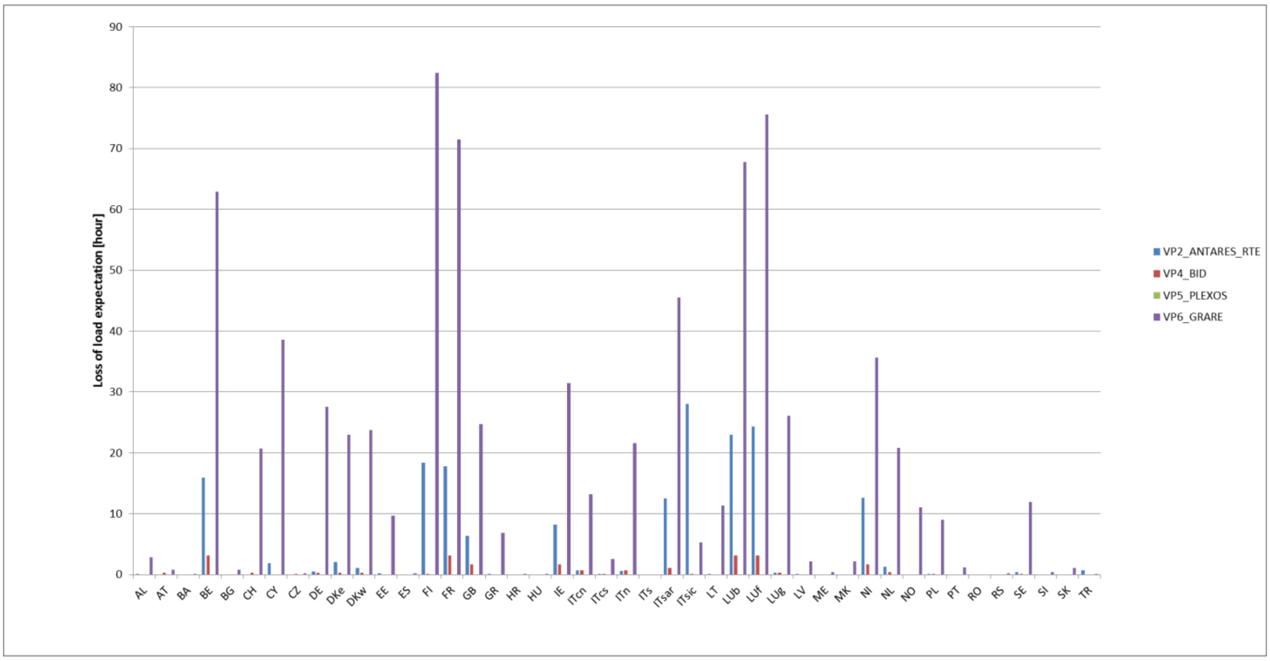

Figure 33 2025 LOLE Base Case

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Table 11 – Average and P95 for ENS (Base Case 2025)

ENS [MWh]	VP2		VP4		VP6	
	average	P95	average	P95	average	P95
AL	1	0	0	0	164	751
AT	0	0	33	200	99	615
BA	0	0	0	0	1	0
BE	30676	135473	809	3437	51809	150177
BG	0	0	0	0	95	568
CH	0	0	27	168	11802	40525
CY	93	442	0	0	1149	5432
CZ	0	0	0	0	5	0
DE	894	5390	248	1462	38786	152784
DKe	1148	5871	8	47	1795	7301
DKw	1084	3509	11	67	4379	17473
EE	28	41	0	0	257	1346
ES	0	0	0	0	117	596
FI	8436	34058	42	364	28722	101119
FR	60872	219638	5595	24378	150440	509024
GB	19690	71808	1951	9432	26802	107377
GR	37	25	0	0	1806	7071
HR	0	0	0	0	3	0
HU	0	0	0	0	0	0
IE	3220	10168	196	676	4556	14834
ITcn	600	3873	53	355	4913	18932
ITcs	85	493	4	13	767	4257
ITn	683	5087	300	2080	15260	53112
ITs	0	0	0	0	0	0
ITsar	1161	3507	73	273	4436	11656
ITsic	6449	18913	0	0	864	3778
LT	7	0	0	0	711	3555
LUb	756	2303	2	9	349	980
LUf	3575	11871	9	41	1550	4596
LUg	248	2879	3	15	2205	8591
LV	0	0	0	0	37	180
ME	0	0	0	0	1	2
MK	0	0	0	0	185	988
NI	3804	10147	57	202	3118	9899
NL	1061	3965	56	317	3618	16005
NO	0	0	0	0	2360	23303
PL	27	0	0	0	1332	6740
PT	0	0	0	0	568	3350
RO	0	0	0	0	0	0
RS	0	0	0	0	5	2
SE	330	1882	0	0	2110	11126
SI	0	0	0	0	1	2
SK	0	0	0	0	28	154
TR	577	3159	0	0	11	0

Table 12 Average LOLE (Base Case 2025)

LOLE [hours]	VP2	VP4	VP6
	Average LOLE	Average LOLE	Average LOLE
AL	0.01	0.00	2.88
AT	0.00	0.35	0.81
BA	0.00	0.00	0.05
BE	15.94	3.19	62.93
BG	0.00	0.00	0.85
CH	0.00	0.35	20.73
CY	1.89	0.00	38.60
CZ	0.00	0.00	0.20
DE	0.51	0.37	27.60
DKe	2.04	0.37	22.99
DKw	1.14	0.37	23.71
EE	0.18	0.00	9.67
ES	0.00	0.00	0.22
FI	18.42	0.15	82.45
FR	17.84	3.19	71.51
GB	6.40	1.66	24.77
GR	0.16	0.00	6.85
HR	0.00	0.00	0.11
HU	0.00	0.00	0.04
IE	8.25	1.66	31.51
ITcn	0.71	0.67	13.26
ITcs	0.16	0.07	2.53
ITn	0.61	0.67	21.60
ITs	0.00	0.00	0.00
ITsar	12.49	1.09	45.48
ITsic	28.01	0.00	5.31
LT	0.02	0.00	11.31
LUb	22.99	3.19	67.74
LUf	24.36	3.19	75.54
LUg	0.35	0.37	26.09
LV	0.01	0.00	2.18
ME	0.00	0.00	0.40
MK	0.00	0.00	2.19
NI	12.63	1.66	35.61
NL	1.32	0.39	20.79
NO	0.00	0.00	11.09
PL	0.05	0.00	8.97
PT	0.00	0.00	1.21
RO	0.00	0.00	0.00
RS	0.00	0.00	0.26
SE	0.43	0.00	11.90
SI	0.00	0.00	0.39
SK	0.00	0.00	1.09
TR	0.73	0.00	0.10

5.2.2 2025 – S2 “Sensitivity – I”

The contribution of operational reserves improves the adequacy situation with respect to the results provided in the Base Case also for 2025.

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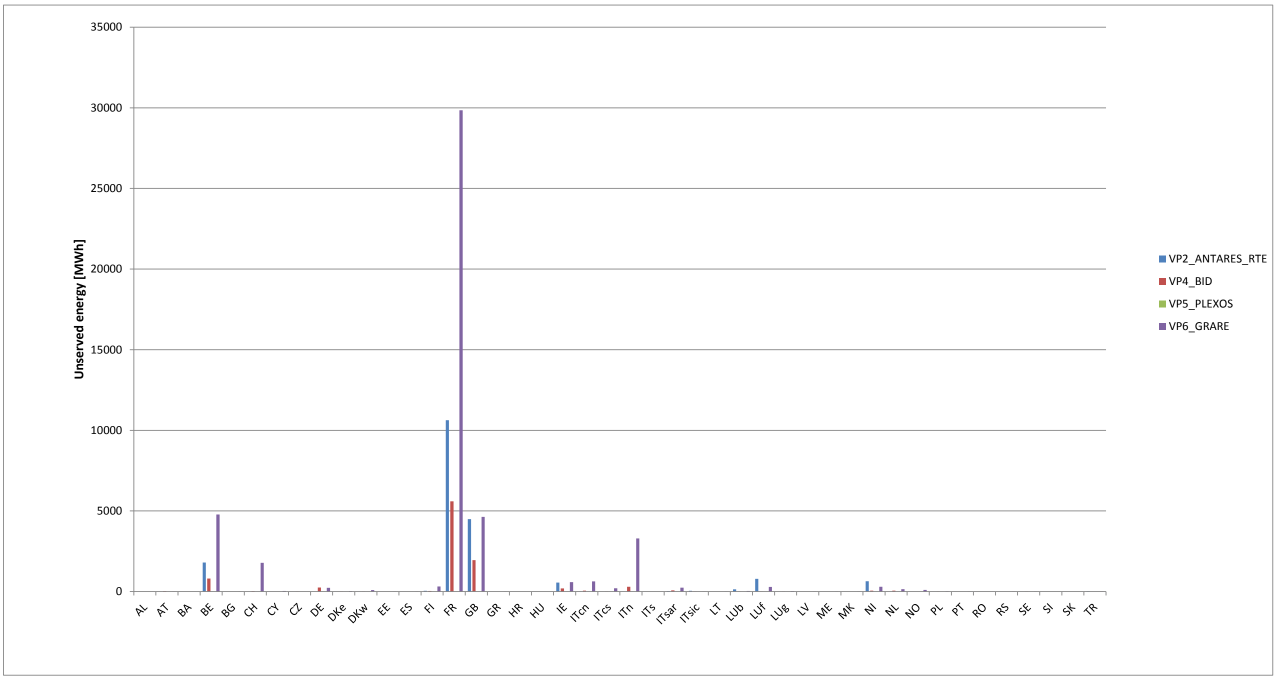

Figure 34 ENS 2025 Sensitivity I

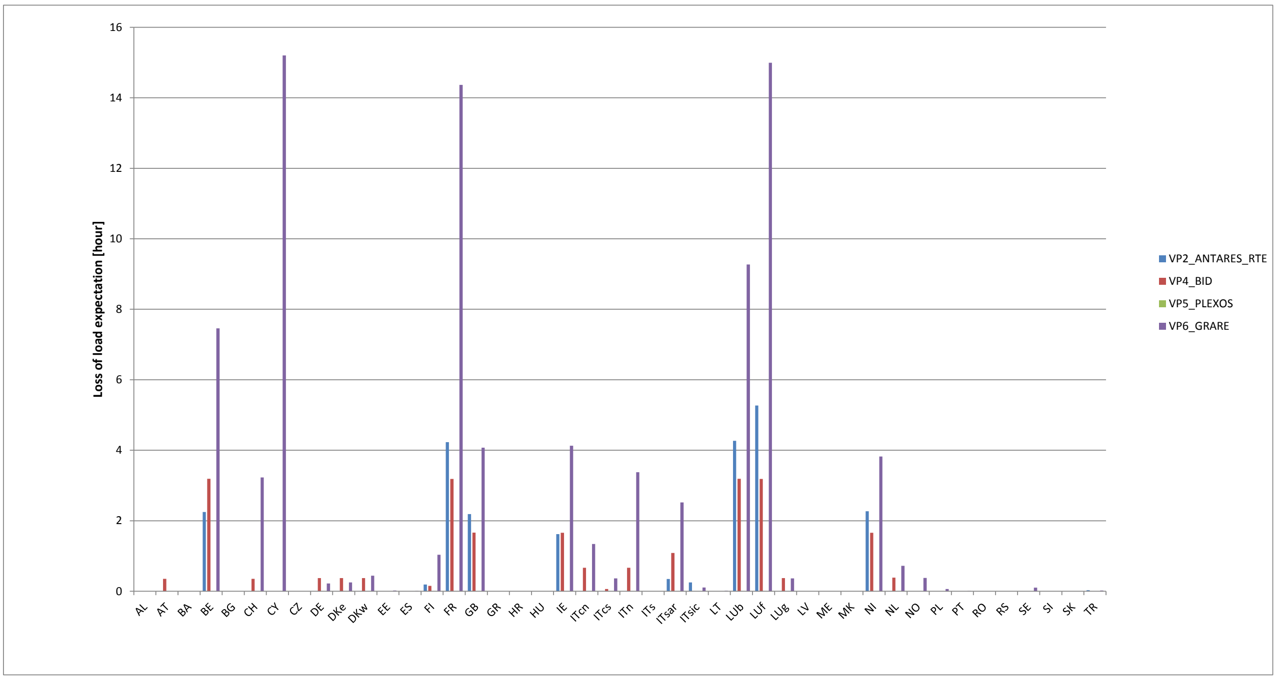

Figure 35 LOLE 2025 Sensitivity I

6 Appendices

6.1 Glossary

ARM	Adequacy Reference Margin
BTC	Bilateral Transfer Capacity
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DSR	Demand Side Response
EENS	Expected Energy not Served
ENS	Energy not Served
FBMC	Flow-Based Market Coupling
IEA	International Energy Agency
IED	Industrial Emissions Directive
LCPD	Large Combustion Plant directive
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MAF	Mid-term Adequacy Forecast
MILP	Mixed-Integer Linear-Programming
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PLEF	Pentalateral Energy Forum incl. (AT, BE, CH, DE, FR, LU, NL)
SO&AF	Scenario Outlook & Adequacy Forecasts
VP	Voluntary Parties

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6.2 Country comments on the MAF 2016

6.2.1 Austria

Load and annual demand forecast provided for 2020 and 2025

For the load forecasts until 2020 it is assumed an increase of approximately 0.9% per year. Beyond 2020 due to energy efficiency an increase of 0,25 % per year is taken into account. The forecasts are based on a normalised load curve assuming average temperatures in the coming years.

Net Generating Capacity forecast provided for 2020 and 2025

The calculations are based on the data collected from market participants for the preparation of the TYNDP 2016. A further increase of renewables (wind, solar and pumped power plants) and shut downs of thermal power plants is expected.

6.2.2 Belgium

Elia recently published 2 reports on adequacy covering different time horizons:

- **Security of Supply of Belgium: Need of strategic reserves capacity for the next winters** (2016-17, 2017-18 and 2018-19) published on December 2015. This study evaluates the need of strategic reserve capacity as defined by the law based on the most recent forecasts of production and demand. This study is a recurrent document delivered to the Minister and the Federal Public Service every year for the 15th of November [*http://www.elia.be/en/about-elia/newsroom/news/2015/02-12-2015-Belgian-security-of-supply-need-for-strategic-reserve*];
- **Adequacy & Flexibility study for 2017-2027**. This study was requested by the Minister of Energy to Elia in order to assess the adequacy and flexibility requirements of the Belgian system for the next 10 years. This study was published on April 2016 [*http://www.elia.be/en/about-elia/newsroom/news/2016/20-04-2016-Adequacy-study-flexibility-Belgian-electricity-system*].

Those 2 studies are using a probabilistic approach (very similar to the one used in the current MAF) and take into account 19 countries. Note that there are some differences in the methodology (that are under consideration for the next MAF):

- Elia uses more climate years;
- Elia takes into account the market based demand side response;
- Elia uses a flow based approach for the years 2017, 2018 and 2019.

Load and annual demand forecast provided for 2020 and 2025

The demand forecast provided for 2020 and 2025 is the same as the one provided in the base case scenario of the study "Adequacy and Flexibility study for 2017-2027" published in April 2016 by Elia.

Net Generating Capacity forecast provided for 2020 and 2025

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The hypotheses from the Elia study 2017-2027 for Belgium in terms of RES, Nuclear, CHP, Biomass, Pump Storage was taken into account in the MAF. A best estimate in terms of gas installed capacity was made for 2020 and 2025 based on the need for adequacy and flexibility identified in the Elia study.

Therefore, the existing gas fired park was considered available for both horizons. This is an assumption and gives no warranty that this capacity will be available at those horizons.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

The study 2017-2027 published by Elia in April 2016 uses a similar probabilistic approach in order to identified the needed additional generation capacity, demand response or storage capacity on top of the capacity considered as available (nuclear, RES, existing pump storage, CHP, existing demand side response on the market and planned interconnection capacity). Note that in Elia's study gas and oiled fired units (other than CHPs) were removed from the capacity considered as available.

Based on the national criteria for adequacy (LOLE average <3 hours and LOLE P95 < 20 hours), the results show no need for additional capacity in 2021. Adding flexibility requirements (to provide ancillary services), there is a need of at least 2 to 4 CCGTs that are required to stay in the system during the whole time horizon.
MAF results show no LOLE for Belgium in 2020, this is in line with the conclusions of the Elia adequacy study 2017-27.

In 2023 and 2025, the nuclear phase-out is planned in Belgium. The need for additional capacity increases to 4000 MW after 2025 in the base case scenario. Note that this capacity is considered as 100% available (no forced outages, nor limitations in energy, nor maximum activations).
In the production park assumptions of Belgium taken into account for the MAF, the needed capacity identified in Elia study was taken into account. The results show that for some of the simulators the LOLE indicators are still above the national criteria of Belgium.
This can be explained by:

- The fact that MAF does not take into account the demand side response of the market (this accounts to more than 1000 MW in Belgium and even more in the neighboring countries) that has a significant impact;
- The different hypotheses within neighboring countries in terms of adequacy levels (mainly in France where adequacy criteria are not met). In the base case of the Elia study, big countries were considered as adequate, assuming they will take the necessary actions to remain adequate (when taking into account energy exchanges and within their national criteria). A sensitivity scenario was also performed by removing more than 40GW of coal generation in Europe ("low capacity" scenario) in the Elia study 2017-2027 where a higher capacity was then identified in order Belgium to be adequate. The MAF assumptions in neighboring countries can be considered as a scenario between the base case and the "low capacity" scenario analysed in the Elia study ;
- Adequacy in Belgium is very dependent on France's adequacy. An additional sensitivity on the available capacity in France was evaluated in the Elia study on the need of strategic reserve for the next winters. The results showed that a reduction of 2.3 GW of

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capacity in France for winter 2016-17 leads to 400 MW additional capacity required in Belgium.

6.2.3 Bosnia and Herzegovina

Load and annual demand forecast provided for 2020 and 2025

Load and annual demand forecast in Bosnia and Herzegovina is based on Production Indicative Development Plan 2016-2025, made by Independent System Operator in Bosnia and Herzegovina and approved by State Electricity Regulatory Commission. Electricity consumption is estimated on the amount of 15.03 TWh in 2025. This Plan is updated every year.

Net Generating Capacity forecast provided for 2020 and 2025

There are large investor's plans in building new thermal power plants in Bosnia and Herzegovina, and in the same time some of old thermal power units would be decommissioned.

Also, there is large interest in building new RES especially wind power plants.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

We do not expect adequacy problems in periods till 2020 and 2025.

6.2.4 Bulgaria

Load and annual demand forecast provided for 2020 and 2025

Load and annual demand forecast for 2020 and 2025 were produced in compliance with the respective guidelines assuming normalized load profile and average temperatures for the reference years. The load curve was linearly scaled using annual demand forecast data from TYNDP 2014. Little to no energy efficiency measures were considered for the resulting forecasts.

Net Generating Capacity forecast provided for 2020 and 2025

The NGC forecast for 2020 and 2025 is based on the inquiries of the market participants made by ESO in relation to TYNDP 2014 and 2016. No major generating facilities' decommissioning is expected for the reference time period. It is presumed that the life cycle of both 1000 MW nuclear units will be extended.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

No significant adequacy issues are expected for the examined years except for possible periods of surplus generating capacities during late spring and early summer when low loads in combination with high RES generation and decreased exports to neighbouring countries may be prerequisites for such an event to occur.

6.2.5 Croatia

Load and annual demand forecast provided for 2020 and 2025

Due to economic crisis in the last six years electricity consumption in Croatia has decreased and was about 17 TWh per year. In the next five to ten year period we expect the recovery of economy and the moderate growth of electricity consumption in Croatia.

Load forecast has been built taking into account medium and long term projections of economic growth rate. Growth of the load depends directly on the industry development and growth of the household consumption. Investments in energy efficiency are expected and that will slightly slow the growth of electricity consumption.

Net Generating Capacity forecast provided for 2020 and 2025

The half of electricity production portfolio in Croatia is hydro power plants and about 10 % are wind power plants. Croatia has already met the objectives of the National Renewable Energy Action Plan in terms of generated electricity by 2020. Still, there is significant interest in building of new RES, especially wind and solar.

There is large investor's interest in building thermal power plants in Croatia, but most of the projects are currently in the initial phase. Decommissioning is planned for a certain number of thermal units which depends largely on the requirements relating to environmental (air) protection. The total installed capacity of TPP till 2020 and 2025 is predicted optimistically.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

At the moment Croatia is dependent on imports of electricity during the whole year which is especially noticeable during the winter months. The capacity of interconnections is high so Croatia can always import sufficient amount of electricity to cover domestic needs.

In the future the increased construction of power plants is expected which will reduce dependence on imported electricity. However, in the coming decade Croatia will be still dependent on the import of electricity especially during the winter months.

Finally, no significant adequacy problems are expected in periods till 2020 and 2025.

6.2.6 Czech Republic

Load and annual demand forecast provided for 2020 and 2025

The growth of annual and peak demand is expected to be moderate until 2025, specifically the annual increment is expected at the rate about 0,3 %. This forecast is based on a normalised load curve assuming average temperatures in upcoming years.

For MAF purposes, the conservative forecast scenario is used and it takes into consideration average economic and demographic growth and minimal growth of electro mobility.

Load and Generation estimates provided for 2020 and 2025 in MAF are in line with expected national forecasts.

Net Generating Capacity forecast provided for 2020 and 2025

Net generating capacity is expected to be decreasing from 2016 to 2025 mainly due to decommissioning of the fossil power plants. However, there will be minor increase of installed capacity in renewables (wind and solar power plants).

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

National studies on Generation and System Adequacy show that the probability of power shortages will be increasing during following years due to shut downs of conventional generation capacities.

When considering commissioning of all expected generation capacities, CEPS does not assume significant problems with the generation adequacy in the Czech Republic. This assumption can be proved by the results of particular MAF probabilistic simulations, and confirmed by Adequacy Indicators (ENS and LOLE). These indicators show that no significant adequacy issues will occur in the Czech Republic until 2025.

National studies on Generation and System Adequacy forecast for 2020 and 2025 correspond with the MAF results.

6.2.7 Cyprus

No need of specific comments has been identified.

6.2.8 Denmark

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Overall, Energinet.dk support the direction in which the overall European evaluations for generation adequacy are moving with the new probabilistic approach in MAF 2016.

Energinet.dk finds that the results in MAF2016 for Denmark overall are in line with our own probabilistic evaluations. It is though important to mention, that for Denmark faults on AC-cables are an important risk element in the evaluations, and hence, we find a higher correlation between adequacy issues in eastern Denmark and southern Sweden compared to the MAF2016. Furthermore, DC-cables are estimated to have an outage level at 8 % in our calculations compared to the 6 % in MAF2016. On the other side, our calculations on energy not served also include the use of part of the reserves.

Furthermore, it is important to mention that Energinet.dk's calculations on energy not served aims at providing the best estimate of energy not served due to adequacy issues on the consumer site. This approach leads to evaluations of risks of additional plants or lines tripping (cascades), i.e. estimates for blackouts at the consumer site as a result of adequacy issues.

6.2.9 Estonia

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

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National TSO adequacy assessment, taking into account the interconnections capability shows that the generation and system adequacy comply with MAF results. In national assessment there is a little shortage of national available generation in 2025 in deterministic N-1 conditions, which is compensated by imports. Taking into account probabilistic and market approach used in MAF shall ensure necessary generation to cover fully the predicted load in 2020-2025. Therefore, in line with the MAF results, TSO expects no ENS in the analysed timeframe.

6.2.10 Finland

Load and annual demand forecast provided for 2020 and 2025

Increase in annual and peak demand is expected to be moderate up to 2025.

Net Generating Capacity forecast provided for 2020 and 2025

Net generating capacity is expected to increase from 2016 to 2020 due to commissioning of new nuclear capacity. By 2025, installed nuclear capacity is expected to further increase while conventional thermal capacity is expected to decrease. New power plants are assumed to have limited availability in the first years of operation to account for possible challenges during commissioning and early operation. Wind power capacity increases moderately in Finland in comparison to many other European countries.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

National TSO studies on generation and system adequacy show that the probability of power shortages has significantly increased during recent years due to mothballing of conventional thermal generation capacity. In terms of detailed results, the range of LOLP and ENS values from different analysis tools used in MAF 2016 is relatively large for Finland, which makes direct comparison with national studies complicated. In general, the main trend shown in MAF 2016, which depicts challenging adequacy situation in Finland in mid-term, is in line with the national TSO studies.

6.2.11 France

Load and annual demand forecast provided for 2020 and 2025

The demand for France in the MAF 2016 for the 2020 horizon is based on the “Baseline” scenario described in the French Generation Adequacy Report 2015 published last year. This hypothesis was the most updated data available at the time of the data collection.

The assumption of annual consumption is around 484 TWh at reference temperature in 2020 which is 5 TWh above the consumption in 2015. For 2025, the level provided around 487 TWh is a projection on the same trajectory. In this scenario, the consumption increases slightly compared with today. This trend is characterized by an increase of the volume of consumption pulled by a medium assumption of Gross Domestic Product growth, new end-uses and transfers, balanced by an improvement in energy efficiency.

Detailed information on the retained scenario is available at:

http://www.rte-france.com/sites/default/files/2016_01_13generation_adequacy_report_executive_summary.pdf.pdf

The impact of temperatures on demand is modelled in the MAF with the use of several load scenarios, which represents a very significant improvement compared to previous ENTSO-E adequacy assessments. The French load is very thermo-sensitive (it accounts for almost half of the European thermo-sensibility). The methodology used to build load in the French Generation Adequacy Report, based on a long experience, is different than the one used in the MAF. It is therefore possible that load shedding caused by extreme weather events may not be detected in the MAF. All efforts to improve the MAF's methodology is strongly supported by RTE.

Net Generating Capacity forecast provided for 2020 and 2025

Net generation capacity forecast for France are mainly based on the Generation Adequacy Report published by RTE in 2015 combined with the most updated information available at the time of the data collection.

In accordance to the MAF's guidelines all power plants considered as mothballed in this document were tagged as available for the MAF, which is an optimistic assumption. Until 2020, renewable energy grows steadily on a medium trajectory. Nuclear power is stable due to the closing of two 900 MW units replaced by a new EPR. The last heavy oil units will have closed in 2020. Hard coal power is stable. For 2025, the net generation capacity assumption is mainly based on the trajectory of the long term scenario "New Mix" published in the Generation Adequacy Report published by RTE in 2014. Others scenarios were studied at the time. Compared to 2020, renewable energy installation rate is enhanced. The nuclear power is decreasing of 10 GW due to withdrawal of several units. One hard coal unit is closed. More information on the features of the "New Mix" scenario and other scenarios studied can be found at:

http://www.rte-france.com/sites/default/files/2014_generation_adequacy_report.pdf

For both 2020 and 2025, generation assumptions are strongly dependent on regulatory and market conditions, and notably on the effective beginning of the capacity market. Assumptions may need to be revised to take into account latest available information.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

The French adequacy assessments performed by RTE are done for a maximum time horizon of 5 years. Differences between the results of the MAF and the French adequacy assessment are explained by modelling differences and the different focus of the two studies. For time horizons longer than 5 years, RTE does not conduct national adequacy studies due to a lack of visibility on hypothesis for adequacy purpose, but only analyses different possible trends for the evolution of the electric system.

Regarding MAF results for France, some main lessons can be drawn from the figures displayed in the report. For 2020, it appears that the LOLE computed for France is significant, but remains consistent with the level of security of supply targeted by the French public authorities. This result is linked to the assumption that the French Capacity Market is active for years 2017 – 2020, as forecasted by market participants at the time of the data collection (some hypothesis for 2020 are based on producers' and aggregators' declarations). Regarding results for 2025, the lack of visibility on hypothesis for adequacy purposes make the interpretation of the results very sensitive. The 2025 point is mainly impacted by the withdrawal of nuclear power plants not balanced by new capacities.

Finally, it should be stressed that any evolution regarding the regulatory framework, market conditions or economic growth may change substantially this forecasted adequacy situation. To tackle this very important point in the 5 years span, the French Generation Adequacy Report evaluates several scenarios on consumption and more and more on production assumptions to assess risks. For longer horizons, the uncertainty is so wide that the adequacy analysis is not performed but replaced by analysis on possible and coherent futures of the electrical mix. More information on the sensitivity and analysis can be found in the French document.

6.2.12 FYR of Macedonia

No need of specific comments has been identified.

6.2.13 Montenegro

No need of specific comments has been identified.

6.2.14 Germany

Load and annual demand forecast provided for 2020 and 2025

In recent years, no clear upward or downward trend for the annual consumption in Germany could be observed. In the best estimate scenarios for Germany, it is expected that future demand will stay on a similar level. It is understood that factors like an efficiency increase and an increase of e-mobility and heat generation will counterbalance each other. For 2020 the assigned values for peak load and annual demand are slightly higher than in 2025. These assumptions are in alignment with legal processes in Germany and have been approved by the German regulator.

Net Generating Capacity forecast provided for 2020 and 2025

In Germany, there is a strong growth of renewable energies and a reduction of conventional power plants expected. The latter particularly relates to lignite and coal power plants. In addition, the German nuclear phase-out will be completed in 2022. The climate protection goals are currently very present in the German debate.

The given conventional capacities are based on power plant lists which have been approved by the German regulator during legal processes. The capacities include generating plants within Germany's geographical boundaries which are participating in the electricity market. In addition, there are different reserve types implemented in the German power system. The existing grid reserve will be further supplemented by the security preparedness of lignite power plants and a capacity reserve in the coming years. However, the reserve units do not participate in the market and **have not been considered in the MAF 2016.**

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

As a result of the strong growth of renewable energies and the expected reduction of conventional capacities due to economic and ecological reasons, system adequacy assessment has also moved into the focus in Germany. The capacity situation in Germany is monitored periodically by the TSOs and the regulator. The politics already set up instruments like grid and capacity reserves to avoid possible bottlenecks in the future. The amount of necessary reserve capacity is periodically identified within legal processes.

A total reserve capacity of about 8 GW can be expected for the year 2020, whereas the amount for the year 2025 is more difficult to quantify. Reserve capacity is not allowed to participate in the regular German electricity market, which makes an adequate consideration of this capacity in the MAF 2016 difficult. However, its impact on the system adequacy situation in Germany is enormous. A consideration in the MAF 2016 would improve the situation for Germany significantly.

6.2.15 Great Britain

Load and annual demand forecast provided for 2020 and 2025

The load and annual demand forecasts for Great Britain are based on National Grid's Gone Green scenario from the 2015 Future Energy Scenarios (FES). There are many different factors driving changes in electricity demand over the next 10 years. This scenario assumes an initial dip in demand compared with today. This is mainly driven by a reduction in industrial demand and energy efficiency gains. Post 2020 we assume that demand grows due to the growth of low carbon heating technologies and electric vehicles.

Net Generating Capacity forecast provided for 2020 and 2025

The generation for Great Britain is also based on National Grid's Gone Green scenario from the 2015 FES. The energy landscape in Great Britain is changing. There are a number of factors driving changes to decarbonise the electricity system in a way that is affordable for consumers without compromising security of supply. The Gone Green scenario has been designed to meet all environmental targets. We expect this will lead to continued growth in renewable generation capacity, particularly for more established technologies such as wind and solar PV. This scenario also assumes additional new capacity from CCGTs, nuclear and interconnectors. This will help to offset the closures of existing, less efficient thermal plant and the decommissioning of nuclear power stations that reach the end of their lifespan.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

There is some uncertainty for the generation outlook in Great Britain as the energy landscape changes. A control measure to mitigate this uncertainty is already in place through the Capacity Market (CM). This will ensure that sufficient capacity is available to meet the reliability standard of

3 hours/year loss of load expectation (LOLE). The LOLE values for Great Britain are higher than 3 hours/year in the MAF. This is due to the modelling assumptions outlined in the main text rather than an indication of potential adequacy problems. Our modelling assumptions will become clearer as we get greater certainty on the capacity being delivered through the CM auctions. The first CM auction for 2020/21 will be held in December 2016.

6.2.16 Greece

Load and annual demand forecast provided for 2020 and 2025

Due to the prolonged economic crisis, growth rate of the electricity demand in Greece has decreased considerably, compared to previous years. The total electricity demand in 2015 amounted to the levels that were observed in 2004. It is expected that with electricity demand will slowly start to increase again, reaching pro-crisis maximum demand (observed in 2008) after the year 2020.

Load forecasts provided for MAF 2016 are obtained from the 'Base Case' development scenario of the latest national TYNDP, complying with the guidelines for MAF. It should be noted that these loads refer to the total demand (loads at the transmission level, as well as dispersed generation from RES at the distribution level) for the mainland and the interconnected islands. More specifically, it is considered that in the year 2017 the Cyclades islands will be interconnected to the system of the mainland, while the island of Crete will be interconnected in two phases. Phase I foresees an AC link 250 MVA (operational in 2020) and Phase II a DC link of 700 MW (operational in 2024B) and therefore loads for 2025 include the demand of Crete as well.

Net Generating Capacity forecast provided for 2020 and 2025

Long-term adequacy assessment has always been challenging, given the wide-range of uncertainties involved, and decentralized planning of projects has made this task even more difficult for TSOs. This is particularly true for the case of Greece, where the prolonged economic crisis and the extensive uncertainties regarding the future of the country has led to behavioral changes of the consumers and private business decisions postponed. IPTO (Independent Power Transmission Operator of Greece) believes strongly that any forecasts beyond the year 2020 are highly unreliable and therefore focus is given on the period up to the year 2020.

With this in mind, only the projects that are under construction, or have already been contracted are assumed in the construction of the MAF scenarios for 2020 and 2025, even though several new plants have obtained generation licenses. It appears that the main factor in Net Generating Capacity evolution for the period 2016 – 2025 will be the decommissioning of old lignite-fired units and the increase of RES capacity.

Confirmed projects include an 810 MW CCGT plant in Megalopoli (which is expected to be operational partially in 2106 and fully in 2019) and a new lignite-fired plant of 620 MW in Ptolemaida (expected in 2022), as well as a couple of new hydro storage plants. Despite the uncertainties regarding the economic situation of the country, it is believed that the signals given by IPTO adequacy studies and ENTSO-e MAF will lead to the realization of viable business decisions for new projects after the year 2020.

In compliance with national legislation and IED 2010/75/EE, PPC (Public Power Corporation) has announced a large-scale decommissioning schedule. Old inefficient units (mainly oil and lignite units) were already decommissioned in 2016, while 1656 MW of lignite units have been included in the limited operation regime. These units are expected to operate only during winter months and after they exhaust their permitted hours they will be retired (end of 2019).

Considering renewable energy sources, and in view of achieving national set targets for 2020, new legislation has given strong motivation for the installation of RES, as well as simplifying licensing procedures. A large number of RES projects have been announced by investors. The scenario developed for MAF 2016 provides a realistic evolution, as seen by IPTO.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Increased RES penetration, namely photovoltaics, in the Greek generation system, as well as shift of consumers to electricity for heating has altered significantly the load patterns observed in the past. Adequacy concerns in the past were always concentrated on the peak loads during midday in the summer months. The last couple of years have shown that, while the total peak loads still occur in those hours, due to the operation of the photovoltaics (over 2,5 GW), peak loads faced by the transmission system now appear during evening hours and annual peaks are shifted to the winter months.

IPTO recently notified the national Adequacy Study for the period 2017 – 2023 to the Regulatory Authority for Energy. Assumptions made regarding the evolution of demand and net generating capacity are very similar, if not in most cases identical to those used in MAF 2016. For the evaluation of adequacy, IPTO calculates on an annual basis the probabilistic indices LOLE and EUE through probabilistic simulation (convolution techniques). A threshold of 2.4 hours/year for LOLE is considered satisfactory. The main difference between the methodology used in MAF and the one used by IPTO is in estimating the contribution of interconnections. While MAF considers a Pan-European perimeter for simulations, IPTO only considers the Greek generation system and interconnections are taken into account through specific scenarios.

Findings of the two studies are similar. It appears that the simultaneous retirement of the lignite fired units of Kardia and Amydeo by 2020 may raise concerns about system adequacy for the Greek generation system in the period 2020 – 2021, and especially under severe conditions (extreme load conditions or a dry spell) the system may need to rely on imports. The introduction of the new lignite-fired unit in Ptolemaida in 2022 seems to compensate for the loss of the other units and LOLE values from then on are in most examined cases below the set target.

6.2.17 Hungary

Load and annual demand forecast provided for 2020 and 2025

For load and annual demand forecast data projections, 2015 Demand Forecast Report of the Hungarian Power System published by MAVIR has been taken as a reference. Data from the Baseline Scenario are used that assumes a moderate annual average demand growth rate of 1% in the first half of the next decade. In order to be in line with the last published national report, load and annual demand data submitted in 2015 for TYNDP 2016 as 2020 Expected Progress scenario have been slightly adjusted.

Net Generating Capacity forecast provided for 2020 and 2025

The Net Generating Capacity forecast for 2020 is based on the TYNDP 2016 2020 Expected Progress scenario with minor modifications reflecting recent developments in Hungary, e.g. in case of solar generation capacity. Only a part of new CCGT capacity addition officially notified to MAVIR has been considered. For year 2025, a new nuclear unit at Paks NPP is included in accordance with the official notification received by MAVIR regarding the expected year of commissioning.

Unlike the past SO&AF reports that contained both conservative and best estimate scenarios, only a best estimate scenario is assessed in the present Mid-term Adequacy Forecast report where more favourable market conditions and overall economic framework were assumed. However, as economic viability of new investments depends on the overall market framework, there is a high risk of delaying or cancelling new projects or prematurely decommissioning existing units based on current market developments. The outcome of these tendencies for Hungary was reflected by the conservative scenarios included in the previous SO&AF reports.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

As only a best estimate scenario was analysed, no adequacy issues have been detected for Hungary and the neighbouring countries. In national reports, a further scenario is analysed where there is growing reliance on imported electricity in the absence of new domestic investments in generation capacity. However, the mid-term availability of excess generation capacity in the region is subject to the overall economic and market framework, as well.

6.2.18 Ireland

Load and annual demand forecast provided for 2020 and 2025

The load forecast for Ireland was developed as the medium scenario for the All-Island Generation Capacity Statement 2016-2025[14] (GCS), published in February 2016. This load forecast has increased from that issued in previous years, due to the expected increase in demand from large industrial users. This brings the average growth to over 2% per annum, reaching 33.5 TWh by 2025.

Net Generating Capacity forecast provided for 2020 and 2025

In formulating the net generating capacity (NGC) of 10 GW for the purposes of the MAF, we have used information provided to us by the generators themselves, and the same assumptions as for the GCS, i.e.

- With a current position of generation surplus, there are no firm plans to build any significant new generation in Ireland, apart from those generators in receipt of some form of assistance (e.g. biomass, wind).
- That some plant will shut down over the course of the next 10 years due to age and/or emissions restrictions.
- That the Capacity Market in the new Integrated Single Electricity Market (I-SEM) for Ireland and Northern Ireland will secure sufficient capacity (including demand-side, interconnection and renewable sources) to meet the adequacy standard.

[14] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_20162025_FINAL.pdf

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In our analysis provided in chapter 5 of the GCS, generators outside of the capacity market are unlikely to recover their costs and would therefore shut down. This is particularly relevant given the high level of renewable generation forecast and the stochastic nature of its performance. Therefore, there is likely to be less generation connected than has been indicated to us and used in this analysis.

There is now a significant amount of RES connected in Ireland, resulting in 28% of all electricity coming from RES in 2015. This is expected to increase further in the years to come, and so the opportunity to study the effect of the intermittency of RES in the MAF studies is most welcome.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

In these MAF studies, and with a NGC of ~10 GW, Ireland's LOLE falls well below its adequacy standard of 8 hours in 2020. This is consistent with the local adequacy studies in the GCS.

However, as the aim of the Capacity Market is to deliver just sufficient capacity to meet the LOLE standard, it is to be expected that any generating unit that fails to secure a capacity payment is unlikely to be financially viable, and so would shut down.

The 2020 MAF results are therefore overly-optimistic and the LOLE is more likely to be at the adequacy standard of 8 hours per year, on the basis that the proposed Capacity Market is successfully implemented. If the Capacity Market is not implemented then EirGrid's analysis, described in chapter 5 of the GCS, shows that the power system would not meet the adequacy standard and there would be generation shortfalls.

The 2025 MAF results for Ireland vary between the different tools, but point to a deteriorating adequacy situation compared to 2020. Even though the NGC remains about 10 GW, significant amounts of thermal plant has closed (primarily due to emissions restrictions), while some intermittent RES have commissioned. The contribution of RES for adequacy purposes is less than for thermal plant. It is to be expected, however, that the proposed new Capacity Market in the I-SEM should secure enough capacity to keep LOLE levels at the standard of 8 hours per year.

As an island, interconnection is vitally important for maintaining adequacy in Ireland. The opportunity to study a pan-European model, with accurate information on interconnection, is very important to help inform local studies. It is particularly beneficial to use a more detailed model for Great Britain and beyond.

6.2.19 Italy

Load and annual demand forecast provided for 2020 and 2025

In line with ENTSO-E best practise when it comes to Energy forecast assumption to be use in the framework of adequacy analysis, Terna refers for the current study to the highest expected growth of the consumption.

According to national grid development plans[15], in the period 2015-2025 it is estimated a total evolution of electricity demand with an average annual rate of 1.2%, corresponding to 354 TWh in 2025.

Net Generating Capacity forecast provided for 2020 and 2025

In Italy, during the last three/four years, the available conventional generation capacity decreased because of the decommissioning of a large number of power plants, mostly old oil-fired power plants, but also because of the mothballing of some recent natural gas combined cycle.

In accordance to the MAF's guidelines, all power plants that are currently mothballed were tagged as available for the MAF, **which is an optimistic assumption**. As an assumption, it gives no warranty that this capacity will be available at those horizons. Furthermore, there are concerns that additional loss of capacity could occur in case of lack of appropriates long term market signals.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Overall, Terna support the direction in which the overall European evaluations for generation adequacy are moving with the new probabilistic approach in MAF 2016. Nevertheless, the current limitations presented by the MAF have pointed out the need to perform sensitivity relevant for account national specificities.

The main gap of the current MAF methodology is represented by:

- capacities between Bidding-Zones are considered as constant across the year. Neglecting the impact of outages, taking into account both the Italian Market configuration - 6 Market Nodes – and physical structure, is a too optimistic assumption that could led to underestimation of adequacy issue, in particular in the main islands: Sicily and Sardinia.

- In the MAF there is only one scenario 'best-estimate' and the methodology doesn't account check of the economic viability: Terna would recommend to consider for the future MAF the possibility of a sensitivity, like in the former SO&AF, where there were space for two scenarios: one more conservative and one more optimistic.

6.2.20 Latvia

Load and annual demand forecast provided for 2020 and 2025

The Load and annual demand forecast provided for 2020 and 2025 in MAF are based on National TSO forecast and follow the Data collection guidelines.

Net Generating Capacity forecast provided for 2020 and 2025

The Net Generating Capacity forecast provided for 2020 and 2025 in MAF are based on National TSO forecast and follow the Data collection guidelines.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

[15] http://download.terna.it/terna/0000/0710/29.PDF

National adequacy analysis, shows that no problems are expected in the period till year 2025. This results can be proven by the results of particular MAF probabilistic simulations, and confirmed by Adequacy Indicators (ENS and LOLE).

6.2.21 Lithuania

Load and annual demand forecast provided for 2020 and 2025

The Load and annual demand forecast for 2020 and 2025 for Lithuania is presented following the Data collection guidelines for Mid-term Adequacy Forecast - MAF16. No Load Management is assumed. Annual demand is forecasted with regards to the most likely projections of economic growth, development of electric vehicles and heat pumps in Lithuania. Some energy efficiency measures are taken into account. The growth is expected to be faster until 2020 and slower in later years.

Net Generating Capacity forecast provided for 2020 and 2025

The NGC forecast is prepared in accordance with producers' information, received during the annual inquiry and the targets, set in National Energy Independence Strategy of the Republic of Lithuania. RES development is obtained by using information from National Renewable Energy Action Plan (NREAP) and the Law on Renewable Energy and other laws governing the development of RES. Decrease of gas fuel capacity is foreseen during the whole period from 2016 to 2025. However, construction of new Nuclear PP (target set out in National Energy Independence Strategy) fully compensates and even increases capacity of Thermal PP in 2025. Increase of RES capacity (mainly wind capacity) is foreseen for the whole period from 2016 to 2025.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Results of National generation adequacy forecast shows that Lithuania has enough capacity to cover demand during the whole analysed period (2016-2025), but even today available generation is usually not competitive in the wholesale market. Therefore large amount of Lithuanian power system demand is covered by imported electricity. However, available capacity of interconnections (even do not taking into account existing strong links with III countries) ensures technical possibilities to import sufficient amount of electricity to cover lack of generating capacity.

6.2.22 Luxembourg

Load and annual demand forecast provided for 2020 and 2025

The load forecast for Luxembourg was developed based on an annual growth of 1.1% according to a GDP scenario STATEC called "base scenario". This moderate scenario used in the study considers a load forecast of 1,18% per annum.

Net Generating Capacity forecast provided for 2020 and 2025

Recent developments in energy market favour coal fired power plants before gas. Gas fired power plants CCGT and cogeneration units are at risk to be decommissioned in the coming

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years. The major CCGT plant in Luxembourg having an installed capacity of 375 MW announced its long term mothballing from October 2015 on. The CCGT is assumed to be decommissioned in 2025 for the study.

A pump-storage with a total capacity of 1300 MW located in Vianden is directly linked to the German Grid and contribution to security of supply in the region.

Renewable generation capacity based on wind and especially solar PV will increase.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

The Luxembourgian generation capacity is specific due to the fact that the main production units located in Luxembourg are injecting in the grid of the neighboring countries Germany and Belgium and thus make an important contribution to the security of supply in the region. The generation and system adequacy relies on imports of electricity thus interconnection capacity of the neighbouring countries Germany and Belgium.

No significant adequacy problems are expected till 2020 and 2025. Nevertheless additional scenarios should be assessed for 2025 horizon.

6.2.23 Northern Ireland

Load and annual demand forecast provided for 2020 and 2025

The load forecast for Northern Ireland was developed as the medium scenario for the All-Island Generation Capacity Statement 2016-2025[16] (GCS), published in February 2016. After declining in recent years, there are indications of demand growth once more, and so this forecast averages 0.4% growth per annum.

Net Generating Capacity forecast provided for 2020 and 2025

In formulating the net generating capacity for the purposes of the MAF (3.6 GW in 2020, 3.0 GW in 2025), we have used information provided to us by the generators themselves, and the same assumptions as for the GCS, i.e.

- Due to the Industrial Emissions Directive, some units are due to close by 2025. This reduces the NGC significantly.

- That the proposed Capacity Market in the new Integrated Single Electricity Market (I-SEM) for Ireland and Northern Ireland will secure sufficient capacity (including demand-side, interconnection and renewable sources) to meet the adequacy standard.

In our analysis provided in chapter 5 of the GCS, generators outside of the capacity market are unlikely to recover their costs and would therefore shut down. This is particularly relevant given the high level of renewable generation forecast and the stochastic nature of its performance. Therefore, there is likely to be less generation connected than has been indicated to us and used in this analysis.

[16] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_20162025_FINAL.pdf

There is now a significant amount of RES connected in Northern Ireland, resulting in 23% of all electricity coming from RES in 2015. This is expected to increase further in the years to come, and so the opportunity to study the effect of the intermittency of RES in the MAF studies is most welcome.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

In these MAF studies, and with a NGC of ~3 GW, Northern Ireland falls well below its adequacy standard of 8 hours LOLE in 2020. This is consistent with the local adequacy studies in the GCS, for the case where Northern Ireland is connected to Ireland with a significant transfer capacity. If transmission re-enforcement projects were delayed, then the adequacy situation would deteriorate.

As the aim of the Capacity Market is to deliver just sufficient capacity to meet the LOLE standard, it is to be expected that any generating unit that fails to secure a capacity payment is unlikely to be financially viable, and so will close.

The 2020 MAF results are therefore overly optimistic and the LOLE is likely to be at the adequacy standard of 8 hours per year, on the basis that the proposed Capacity Market is implemented. If the Capacity Market is not implemented then SONI's analysis, described in chapter 5 of the All-Island Generation Capacity Statement, shows that the power system would not meet the adequacy standard and there would be generation shortfalls.

The 2025 MAF results for Northern Ireland vary between the different tools, but point to a deteriorating adequacy situation compared to 2020. The NGC has reduced to 3 GW due to significant amounts of thermal plant closing (because of emissions restrictions). It is to be expected, however, that the proposed new I-SEM Capacity Market should secure enough capacity to keep LOLE levels at the standard of 8 hours per year.

As an island, interconnection is vitally important for maintaining adequacy in Northern Ireland. The opportunity to study a pan-European model, with accurate information on interconnection, is very important to help inform local studies. It is particularly beneficial to use a more detailed model for Great Britain and beyond.

6.2.24 Norway

Load and annual demand forecast provided for 2020 and 2025

We expect increased economic activity, population growth and electrification in heat and transport to overweigh overall energy efficiency up to 2025. This results in a slightly increased demand in 2020 and 2025 up from today's level.

Net Generating Capacity forecast provided for 2020 and 2025

The common Swedish and Norwegian Green Certificate Market contributes to some new hydro and wind power in Norway up until 2020/2021. After 2020 there may be some upgrading of

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existing old hydro power stations, but we expect limited growth in net generating capacity between 2020 and 2025.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

A Statnett study from 2014 ("SAKS 2014") concluded that the risk of energy rationing (reservoirs running dry) in Norway in 2022 is very small. This is the case also in a dry year and if large amounts of nuclear or interconnection capacity is unavailable. Looking only at the national level, the risk of power shortage is also very small. We do not expect peak load to increase higher than the lowest available winter capacity.

We are positive to the new probabilistic methodology in MAF 2016, but also recognize that there are challenges around adequacy studies. How to define loss of load or rationing is one key question. In a strained market situation, Norway may reduce its load and increase the export, if the reduced Norwegian demand has a lower willingness to pay for power than the demand in the strained neighboring country. We would not define this as loss of load, but as a well-functioning market where all actors provide appropriate information. Another challenge is to model the Nordic hydropower system with a model that does not handle the hydropower strategy and water values directly. Only transferring reservoir curves between models may not provide enough information to adequately model the system in strained situations. We are therefore cautious to the results for 2025 (B) scenario under conservative modelling asumptions. While it is not impossible to see loss of load in a very extreme market situation, the ability of hydropower to rapidly adapt their bidding strategy makes it quite unlikely.

6.2.25 Poland

Load and annual demand forecast provided for 2020 and 2025

PSE forecast of the annual demand increase has not changed comparing previous SO&AF 2015 report and amounts to 1.5% for period 2015-2020 and 1.6% for 2020-2025.

Hourly load series refer to normal conditions and the increase fit to demand growth.

Net Generating Capacity forecast provided for 2020 and 2025

Net Generating Capacity (NGC) data for Expected Progress scenario was delivered for MAF 2016 in January/February 2016 and based on information from producers collected until the end of August 2015. The development of NGC (both, commissioning and decommissioning of generations resources) refers to favourable economic conditions.

1. Information on the subject of derogation clause from LCP and IE directives in Poland

During negotiations on its accession to the European Union (joined May 1, 2004), Poland achieved the derogation clause from LCP Directive (2001/80/EC), which came into effect in 2008 (for SO_2) and 2016 (for NO_x). The derogation clause from the Directive means that the emission limit values will not apply until January 1, 2016 for SO_2 and January 1, 2018 for NO_x for selected power stations and combined heat and power plants (CHPs). No derogation for power plants is in force for dust.

The IE Directive (2010/75/EU), implemented in Polish law in July 2014, amends the LPCD and the IPPCD and introduces new, more restrictive limits concerning SO_2, NO_x and dust emissions for power plants as well as for CHPs. It will come into effect from 2016, although when taking into account the derogation described above, the new limits for NO_x emission for the groups of producers listed in the accession treaty will be in force in Poland not earlier than at the beginning of 2018.

2. The level of fossil fuel power plants decommissioning

The Polish TSO, based on present producers' declaration, assesses that in Poland the following decommissioning of fossil fuel Net Generating Capacity will take place in Expected Progress scenario:

- at about 3.6 GW between the end of 2015 and the end of 2020,
- at about 0.8 GW between the end of 2020 and the end of 2025.

3. Development of NGC

There are eight new commissioning of big fossil fuel units taken into account with projected gross installed capacity:

- o hard coal: 1075 MW, 910 MW and 2 x 900 MW,
- o lignite: 496 MW,
- o gas: 596 MW, 473 MW and 467 MW.

Estimated NGC of this units amounts to 5.4 GW

All of these units are expected to be commissioned before 2020. A development of RES is assumed until 2025 up to 12.5 GW (including renewable part of hydro and other renewable sources).

4. Best Available Techniques (BAT) Conclusions.

Due to fact, that BAT conclusions were not passed yet, to MAF 2016 Expected Progress scenario data without influence of BAT on generation resources was provided. It is assumed, that most of fossil fuel generation resources in Poland will be affected by BAT standards, however the level of necessary adjustments and costs of them will be different in each case. Therefore, there will be very strong sensitivity of the level of possible modernization to further market conditions. Due to this uncertainty in March 2016 PSE prepared additional analysis which evaluated the influence of BAT conclusions on the system. PSE prepared two scenarios:

- Decommissioning scenario, in which already forecasted level of decommissioning (totally 4.4 GW till 2025) will be enlarged by additional 6.2 GW of power till the end of 2025 (in fact till the end of 2021[17]). This decommissioned power will not be adjust to fulfil BAT standards due to unfavourable economic conditions. In this worst scenario, total decommissioning power amounts to 10.6 GW.

[17] It is predicted that BAT Conclusions will come into effect in 2021.

- Modernization scenario, which assumes favourable economic conditions. Among others, this conditions allow carrying out the necessary investments in the mentioned above 6.2 GW of generations resources to be able to fulfil BAT standards

It is worth saying that all generation resources, in which an adjustments will be necessary, are forecasted to be periodically classified as additional, not available power due to required overhauls.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Results of national adequacy forecast and MAF 2016 results cannot be comparable in a direct way due to different methodology as well as different assumptions.

Nevertheless MAF 2016 probabilistic analysis also show possible problem in adequacy in Poland, therefore it is important to note, that the current development of generation resources may not be enough to balance the system in the future.

In addition, based on analysis of the MAF results, PSE assess that the adequacy results will be much worse due to following aspects:

1. Influence of BAT Conclusions.

As described above data provided to MAF does not take into account the influence of BAT Conclusions on fossil fuel generation resources in Poland. Regardless of economic condition scenarios, the mentioned above 6.2 GW of power will require modernization (periodically out of operation due to overhauls) or simply will be shut down with significant influence of power balance in Poland.

2. Relation between load and the level of outages / non-usable capacity.

Since years PSE has observed close relation between load increase and the level of outages / non-usable capacity. When the load is much higher than in normal conditions and most of available fossil fuel generation resources are in use, the level of outages / non-usable capacity is increasing. Outages, which in Polish case include non-usable capacity, were simulated randomly, therefore the impact of higher level on outages will not be visible in adequacy results.

3. Low level of load series prepared for 14th climatic years.

PSE analysed hourly load series use in modelling. The increase of load in high load periods (mainly peak loads) in all simulated climatic years (2000-2013) looks to be negligible comparing to normal conditions. In previous SO&AF PSE forecasted, that winter peak load will be higher by at about 0.5 GW (summer peak even more). This may direct influence on adequacy results. The sensitivity of load to temperature will be analysed before next edition of MAF.

4. Availability of interconnection.

PSE forecasts that following import capacity will be available in Poland:

- 1.82 GW in 2020,
    - of which 0.5 GW refer to synchronous profile (DE+CZ+SK)
    - of which 0.6 GW from Sweden
    - of which 0.5 GW from Lithuania

  - of which 0.22 GW from Ukraine
- 4.32 GW in 2025,
  - of which 2.0 GW refer to synchronous profile (DE+CZ+SK)
  - of which 0.6 GW from Sweden
  - of which 1.0 GW from Lithuania
  - of which 0.72 GW from Ukraine

The provided import capacity on Polish synchronous profile has partially taken into consideration the possible congestion resulted from unscheduled flows through Poland from the west to the south. Nevertheless a situation may occur, when the forecasted level of import capacity will not be fully available to cover tight power balance periods / hours due to high level of unscheduled flows.

PSE states the position, that simulations of the use of interconnections should not base on NTC method. The method should allow the correct coordination of capacity calculation and allocation in the meshed centre of the Continent. It could be i.e. flow-based approach in the proper region, which means Continental Europe East, West and South with properly configured bidding zones (control blocks at least).

For MAF 2016 simulations import from Ukraine was not taken into account.

6.2.26 Portugal

Load and annual demand forecast provided for 2020 and 2025

MAF 2016 electricity demand in Portugal for both 2020 and 2025 is based on the national high growth estimation along with efficiency measures as defined in the revised “National Energy Efficiency Action Plan” and consumption from electric vehicles according to the “National Renewable Energy Action Plan”. These forecasts correspond to long term estimations performed in 2014, and ensure consistence between data provided for MAF 2016 and TYNDP 2016. No Load Management is assumed.

Net Generating Capacity forecast provided for 2020 and 2025

Portuguese electricity system is characterized by high penetration levels of renewable energy that are already able to supply more than 50% of annual electricity demand. National strategies for energy development support further growth of RES by setting new goals for 2020 and beyond, mainly by increasing pumped-storage hydro, wind and solar capacity.

The MAF expected scenario of generating capacity for 2020 and 2025 is based on national energy policy drivers defined by the Portuguese government (as foreseen in 2014). Also the compliance of national Security of Supply standards[18] is taken into account in order to identify needs of further capacity.

Main developments in generation include the increase of renewable energy sources until 2020, particularly wind power, reaching 5 300 MW, as well as large hydro power plants up to 7 400 MW

[18] Security of Supply standards in Portugal: Load Supply Index (LSI)≥1,0 with 95% exceeding probability and Loss of Load Expectation (LOLE)<8h/year (taking into account the lack of operational reserve)

(of which nearly 3 300 MW pumped storage). Additional large hydro (+1 155 MW) is foreseen between 2020 and 2025, most of it increasing pumping capacity (+880 MW), which is necessary to compensate the volatility of intermittent generation from wind and solar. Decommissioning of old coal and gas power plants (2 745 MW) is expected between 2017 and 2024, partly replaced by new CCGT units (880 MW).

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

In both 2020 and 2025, foreseen generation capacity is expected to comply with Portuguese adequacy standards. In case of 2025 this outcome requires the integration of new CCGT units if old thermal power plants are decommissioned as assumed in MAF 2016.

Results from the national assessment of security of supply for the above mentioned scenarios in 2020 and 2025 are consistent with MAF 2016 indicators (for the Base Case and Sensitivities), whereas LOLE and ENS are nearly zero..

6.2.27 Romania

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Results from MAF 2016 serve as reference for the national assessment of security of supply. Load and Generation estimates provided for 2020 and 2025 in MAF are in line with the expected national forecasts.

6.2.28 Serbia

Load and annual demand forecast provided for 2020 and 2025

In the period 2016-2020 an increase of electricity demand is estimated with an average annual rate of 1.23 %, corresponding to consumption of 41,7 TWh in year 2020. Forecast of the annual demand increase is around 1.1 % for the period 2020-2025 and amount to consumption of 44,1 TWh in 2025.

Net Generating Capacity forecast provided for 2020 and 2025

The increase of the capacity from renewable sources is expected to come primarily from wind power, reaching around 1000 MW until 2025. The net generating capacity of TPP on fossil fuel is expected to decrease, mainly because of the Industrial Emissions Directive and Large Combustion Plant Directive of EU.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

National adequacy analysis, shows that no problems are expected in the period till year 2025. This results can be proven by the results of particular MAF probabilistic simulations, and confirmed by Adequacy Indicators (ENS and LOLE).

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6.2.29 Slovakia

Load and annual demand forecast provided for 2020 and 2025

According to the methodology of Data collection guidelines for MAF16, the annual demand for both years 2020 and 2025 from the scenario B of the report Scenario Outlook & Adequacy Forecast 2015 was kept. The load and annual demand forecasts are in line with the national development plan of SEPS and it stems from the separate electricity consumption forecast study of the Slovak Republic by 2050.

For MAF16 purposes the high-load forecast scenario is used and it takes into consideration more intensive economic and demographic growth and bigger electromobility growth as well. At the same time, there is expected to be a decrease in the energy intensity because of technology innovation that is associated with exchange of obsolete technology for energy-efficient technology.

However, regarding the above-mentioned facts, which take into account the high expected growth of the electricity consumption, it is necessary to mention that in reality we do not assume so rapid growth of electricity consumption for time horizons 2020 and 2025.

Net Generating Capacity forecast provided for 2020 and 2025

Compare to the present time there is a significant change of proportion of the different power plants' technologies in the total NGC for the time horizons 2020 and 2025.

The mentioned changes relate primarily to nuclear power plants. The most significant increase in NGC is expected due to commissioning of two new nuclear units in Mochovce (approximately 995 MW till the end of 2018). The NGC increase in nuclear power plants is affected by increasing the NGC of existing nuclear power units, as well.

Another factor that has a significant and positive impact on NGC is gas-fired technology because it is considered that approximately 620 MW (netto) in gas units included in the Non-Usable Capacity (NuC) in the present time will be put back in operation for the time horizons 2020 and 2025. However, it is necessary to mention that the exclusion of mentioned gas-fired technology from NuC depends mainly on redemption electricity price evolution and to some extent on future gas market price, as well.

With regard to hard coal-fired technology, the 220 MW in hard coal was definitively decommissioned in 2014.

In early 2016, there was decommissioned additional capacity of 220 MW in lignite fired technology.

An increase of generating capacity in the fossil fuel technologies which are included in the PEMMD Thermal category for the time horizons 2020 and 2025 is currently not expected.

As regards as renewable energy sources (RES), the prognoses in evolution of RES capacity in particular to 2020 are negligible from realistic TSO prognoses.

With regard to hydro technology, there is not expected construction of any hydro power plant with a significant installed capacity. Only increase of 10 MW installed capacity in small hydro power plants between 2020 and 2025 is approximately considered.

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National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

When considering commissioning of all expected generation capacities (mainly the new nuclear units, and gas fired technology sources included in the NuC at the present), we do not assume problems with the generation adequacy in Slovakia. This fact is confirmed by the results of particular MAF16 probabilistic simulations, and specifically confirmed by Adequacy Indicators ENS and LOLE. These indicators prove that no adequacy problems on Slovak territory for 2020 and 2025 time horizons are assumed.

6.2.30 Slovenia

Load and annual demand forecast provided for 2020 and 2025

The demand forecast is mainly based on GDP growth and demography development. In the past there was a close correlation between these variables and it is expected to stay the same in the future. The extent of future GDP is estimated on the basis of the multisector macroeconomic theoretical model of exogenous growth, based on the model of the dynamic stochastic general equilibrium (DSGE). Current trends show that Slovenia is recovering from the economic crisis, thus the constant demand growth is expected. Electricity consumption in Slovenia in 2015 was 12.7 TWh. In the most optimistic scenario the growth is expected to reach 16.5 TWh in 2025. The expected peak load is also expected to rise, from 2.05 GW in 2015 up to 2.48 GW in 2025.

According to the methodology, the same load and annual demand forecast for time horizons 2016, 2020 and 2025 are considered.

Net Generating Capacity forecast provided for 2020 and 2025

The net generating capacity (NGC) in Slovenia is subjected to large uncertainties due to rapidly changing situation on the electricity market in Europe. In the last year, due to low purchase prices the thermal power plant Trbovlje was permanently closed. Other thermal units are also facing major challenges regarding economic sustainability. Nevertheless, considering optimistic scenario development the NGC is expected to increase because of new hydro power plant units on the Sava River, a new pump-storage unit on the Drava River, gas units in Brestanica, and a new lignite thermal unit in Šoštanj, which obtained its operating license in 2016.

Beside the development of conventional generation a further increase of renewables (solar and pumped power plants) is expected. The increase is expected to mostly with solar and pumped power plants, whereas the share of wind power plants is not expected to develop anytime soon and also there is no noteworthy share of wind power plants in Slovenia.

It should also be noted that the ownership of the existing nuclear power plant at Krško is equally divided between Slovenia and Croatia, which is a unique case in Europe, thus all capacity calculations assume half of its production is delivered to Croatia according to the international agreement between both countries.

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National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

National TSO studies on generation and system adequacy show that Slovenia currently meets the LOLE recommendations taking into account around 500 MW import. Furthermore, from 2016 onward LOLE is expected to constantly decrease each year until 2020, which is due to new hydro power plant units on the Sava River and new pump-storage unit on the Drava River. However, because of constantly increasing consumption, LOLE is expected to be increasing from 2020 on.

The unavailable capacity is higher in winter than in the summer because of the unavailability of PV generation at that time and insufficient hydrology. It should be mentioned that hydro power plants hold more than a 30 % share of all installed power in Slovenia.

In contrast, interconnectors have an important role in terms of electricity export, as well. Till 2025, the interconnection capacities will increase because of the new interconnection lines with Hungary and Italy (new interconnectors to Italy are still under consideration) and also because of reinforcement of the internal grid.

6.2.31 Spain

Load and annual demand forecast provided for 2020 and 2025

Load and demand forecast provided for 2020 is consistent with the one included in the Spanish Master Plan and the 2020 horizon of TYNDP16. For 2025 a lower growth rate of the demand is expected related to efficiency measures and a slowdown in the rate of electrification compared to the one registered over the last decades.

Net Generating Capacity forecast provided for 2020 and 2025

The generating capacity forecast provided for 2020 is the one included in the Spanish Master Plan (with some minor updates).

The increase of the capacity between 2020 and 2025 is expected to come from renewable resources (PV and wind technologies). Coal power plants decommissions are foreseen, mainly because of the European Emission Directive. Regarding nuclear power, the extension of the life cycle of the existing plants is assumed.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

As it happens in the MAF2016, under the assumptions taken in the national analysis no major issues are expected regarding Spanish System Adequacy in 2020 and 2025.

6.2.32 Sweden

Load and annual demand forecast provided for 2020 and 2025

Forecasts of the yearly electricity consumption are used as a reference value when the loads of the reference times have been approximated. Since 2008, the Swedish electricity consumption has been low due to the financial crisis, as electricity consumption is closely linked to economic activity. However, it should be mentioned that the Swedish electricity consumption has hovered around 135 – 150 TWh during the last decade whilst there has also been a trend of a stable consumption in Sweden even before the financial crisis. Due to continuously energy efficiency measures and reduced use of electricity for heating, the consumption is not expected to increase.

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Therefore the electricity consumption in 2020 is expected to be about 142 TWh and the same in 2025.

Net Generating Capacity forecast provided for 2020 and 2025

The NGC of nuclear power is expected to decrease due to decommissioning. It is also expected that a large increase of capacity from renewable sources is driven by subsidies. The increase of the capacity from renewable sources is expected to come primarily from wind power. The NGC of fossil fuels is expected to decrease.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Some minor adequacy issues can occur in 2025 due to reasons as decommissioning of nuclear power.

Historically, Svenska kraftnät has been procuring strategic reserve capacity for each winter season. The strategic reserve consists of both production capacity and load that can be disconnected.

6.2.33 Switzerland

Load and annual demand forecast provided for 2020 and 2025

The annual load for Switzerland is consistent with the Swissgrid's "Strategic Network 2025" (published in 2015) network planning scenario "On Track", which in turn was constructed to be in line with the Swiss "Energieperspektive 2050" NEP (Neue Energiepolitik) Scenario. Effectively it means that the values for MAF were either directly taken from the scenario when available or derived in a consistent way when not available or published.

For the temperature-sensitive hourly profiles with different climate conditions they were derived based on the cubic-functions computed from the most recently available historical load data available to Swissgrid. This allows temperature-dependent hourly load values to be derived according to different climate conditions, e.g. cold/heat-waves. These are important inputs required for the probabilistic analyses in MAF.

Net Generating Capacity forecast provided for 2020 and 2025

The installed generation capacity for Switzerland is consistent with the Swissgrid's "Strategic Network 2025" (published in 2015) network planning scenario "On Track", which in turn was constructed to be in line with the Swiss "Energieperspektive 2050" NEP (Neue Energiepolitik) Scenario. Effectively it means that the values for MAF were either directly taken from the scenario when available or derived in a consistent way when not available or published.

The different hydrological years, i.e. dry, wet and normal, as well as their occurrence probabilities, were a result of the collaboration work in PLEF 2015, in which correlated hydro conditions in Austria, France and Switzerland were analysed. These account for the amount of water available weekly for hydro production for both run-of-river and storage plants.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

When compared to the national studies, The 2020 MAF results were as expected, i.e. one would not expect adequacy problems for Switzerland, based on the methodology and the underlying modelling assumptions.

For the year 2025 the MAF results indicated that Switzerland could have generation adequacy problems, contrary to Swissgrid's expectation. The reason for this discrepancy is because of the hydro-optimisation and thermal plants' forced-outages modelling. In a conservative setting one assumes that one has only prior-knowledge of fixed forced outages (independent from the actual Monte-Carlo draws) and also would not be able to adjust the dispatch after the forced outage is known, while in a less conservative setting one assumes that one could foresee forced outages in advance and plan accordingly. This could respectively result in a different valuation of adequacy situations. In MAF this conservative setting was taken by one of the tools, this resulted in very tight conditions in the alpine region which has significant amount of hydro installed capacities. Not only would Switzerland be affected by this but also its neighbouring countries which have hydro production, with less import from neighbouring countries plus the lack of own hydro production this resulted in high amount of LOLE and ENS for Switzerland in year 2025.

However, the reality is in between these two extreme cases, because even though forced outages, according to their definition, cannot be known well in advance in practice, but utilities should know soon after the outage starts and be able to re-optimise their schedules accordingly. For hydro-countries, utilities usually optimise their dispatch with a moving time-window, unlike a fixed window in the MAF simulations. With the well-known high flexibility of the hydro-plants they can adapt very quickly based on the prevailing market and system conditions.

It should be noted that, however, MAF is a generation adequacy forecast and its focus is not on network analyses. Because of that the winter situation as observed in Switzerland in 2015/2016 initially caused by internal congestion was not considered in the current MAF.

6.2.34 The Netherlands

Load and annual demand forecast provided for 2020 and 2025

Whereas in the past there was a close correlation between GDP growth and the growth of electricity consumption in the Netherlands, this link will become less relevant in the future. For the 2020 and 2025 time horizons a very moderate growth of the electricity consumption is expected. The low growth is mainly caused by the increasing influence energy conservation measures. The assumption for the demand forecast used in the MAF are reasonably in line (within a 1% margin) with the latest expectations that will also be used in the upcoming national adequacy report.

Net Generating Capacity forecast provided for 2020 and 2025

The assumptions with respect to the development of the supply as used for the MAF are slightly deviating from the latest insights. In the latest forecast, used for the upcoming national adequacy report and the national grid development plan, a bit larger reduction of operational thermal generating capacity is expected. This reduction is mainly due to a further increase in the decommissioning and mothballing of thermal generating capacity.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

As a statutory duty, TenneT publishes a national adequacy report every year. The next report, will be published in end of August 2016. The report published in 2015 can be found here: Report on Monitoring of security of supply 2014-2030.

The probabilistic assessment method used by TenneT is comparable with the MAF methodology. TenneT actively supports the new methods developed for Regional (e.g. PLEF) and Pan European (MAF) adequacy assessment.

Although there are slight differences in the assumptions between MAF and the new national report, we expect the results, with no issues in 2020, to be in line with each other.

6.2.35 Turkey

Load and annual demand forecast provided for 2020 and 2025

Turkish electric system is expected to grow very fast for the future. Annual growth rate is around 5% for both peak demand and consumption. Major factors effecting electricity demand are mainly population growth, urbanization rate, industrial development targets and economic development expectations. Population is still increasing more than 1% per year, this means that there is a considerable amount of young people, so country should develop more and more. This development needs electricity demand increase.

Ten year period is exactly a short term to estimate economic and industrial development in a country, so electricity demand forecast can be estimated more accurately. Economic and industrial targets are determined in Turkey by ministries and infrastructural investments are planned according to these targets. Electricity demand forecast is directly related to development targets, so demand estimation for years 2020 and 2025 should be more realistic.

Demand forecast studies are revised every two year by the Ministry of Energy and Natural Resources. Peak and energy demand for years 2020 and 2025 are from these demand projection series. Hourly loads are simulated by using historical actual consumption.

Further, Annual Load Factor is quite high, actual value is above 70% and it is expected that it will continue as this level for next 20 years. As it is known, sectoral shares of annual electricity consumption directly affects the load factor. The larger industrial share, the higher annual load factor. Industrial sector share in annual electricity consumption is around 60% currently and in order to reach development targets for the future this share is expected to remain at this level. By this fact, hourly demand simulation is based on recent years' actual hourly loads.

Net Generating Capacity forecast provided for 2020 and 2025

Turkish electric system has almost all known resources, except nuclear, for power generation. The first nuclear plant is expected to be in service after 2023. Capacity based on renewable resources, mainly wind and hydro (RoR), are increasing considerably for last several years.

Major factors affecting availability of thermal power plants are forced outage due to failure, annual maintenance requirement, fuel quality and fuel supplying constraints. Availability of thermal power plants are calculated based on these major factors. Forced outage rate and annual maintenance period are assumed as accepted standards. It is assumed that there will be no fuel insufficiency and the fuel quality will be as desired.

Availability of renewable capacity is mainly based on climatic conditions beside forced outage rate and annual maintenance. Water inflow for hydro and wind blow for wind capacity are main effects. It is too difficult to predict water inflow and wind blow for the future. Actual hourly generation values of hydro and wind capacity may give an idea for possible future generation profile. Hourly generation values of renewable capacities have been simulated from actual historical hourly generation.

In order to determine the Net Generating Capacity for years 2020 and 2025, major effects for availability is considered.

National view on Generation and System Adequacy forecast for 2020 and 2025 and its relation to the MAF results

Electric sector is fully liberalized in Turkey, only transmission is under responsibility of government. Generation investments are realized by private companies. Generating facility investors are free to choose region, resource, technology and timing. Long-term Electricity Generation Planning Studies are carried out only for indicative purpose. Data for years 2020 and 2025 are derived from the last Generation Planning Study, but this study is not an investment planning.

MAF results may be useful for generation investors and also for transmission investments. Transmission system expansion is mainly based on demand increase and generation plant investments, but these results are expected to be considered for appropriate investments.

6.3 Model descriptions

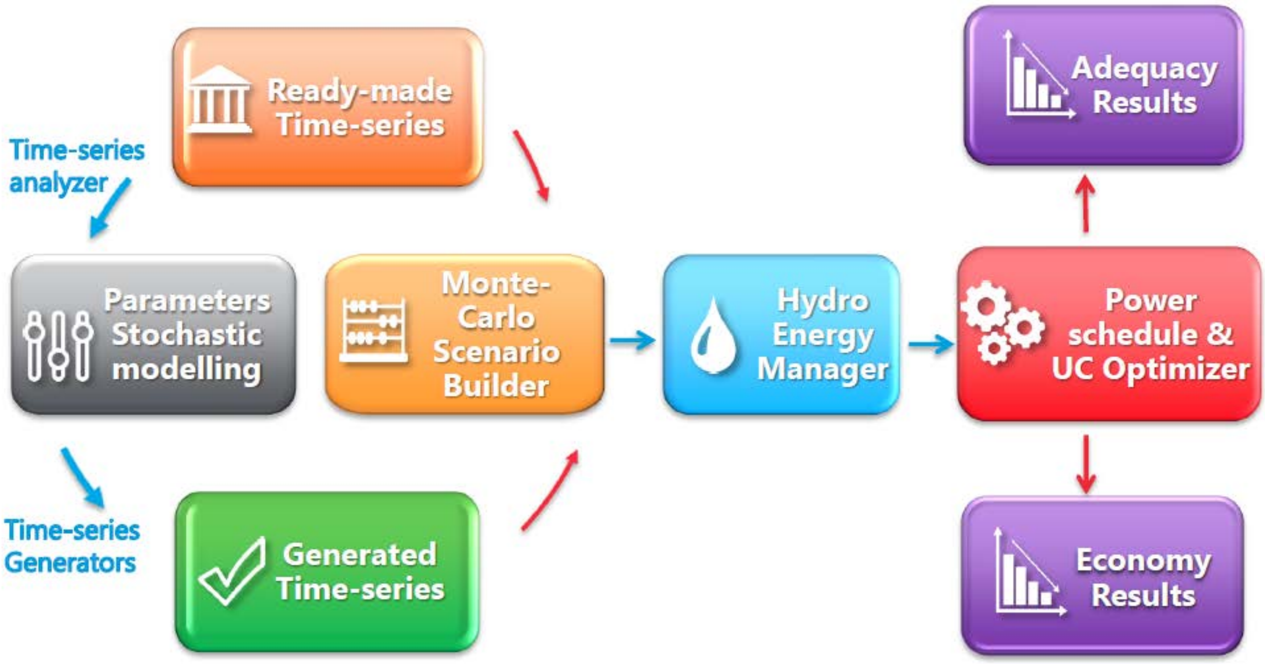
6.3.1 ANTARES

ANTARES - A New Tool for generation Adequacy Reporting of Electric Systems – is a sequential Monte-Carlo multi-area adequacy and market simulator developed by RTE. The rationale behind adequacy or market analysis with a Monte-Carlo sequential simulator is the following: situations are the outcome of random events whose possible combinations form a set of scenarios so large that their comprehensive examination is out of the question. The basis of the model is an optimizer connected in output of random simulators.

Antares has been tailored around the following specific core requirements:

a) Representation of large interconnected power systems by simplified equivalent models (at least one node per country, at most #500 nodes for all Europe)
b) Sequential simulation throughout a year with a one hour time-step
c) For every kind of 8760-hour time-series handled in the simulation (fossil-fuel plants available capacity, wind power, load, etc.), use of either historical/forecasted time-series or of stochastic Antares-generated time-series
d) Regarding hydro power, definition of local heuristic water management strategies at the monthly/annual scales. Explicit economic optimization comes into play only at the hourly and daily scales (no attempt at dynamic stochastic programming)
e) Regarding intermittent generation, development of ***new stochastic models*** that reproduce correctly the main features of the physical processes (power levels statistical distribution, correlations through time and space)

At core, each Monte-Carlo (MC) year of simulation calls for two different kinds of modelling, the first one being devoted to the setting up of a ***"MC scenario"*** made up from comprehensive sets of assumptions regarding all technical and meteorological parameters (time-series of fossil fuel fleet availability, of hydro inflows, of wind power generation, etc.), while the second modelling deals with the economic response expected from the system when facing this scenario.
The latter involves necessarily a layer of market modelling which, ultimately, can be expressed under the form of a tractable ***optimization problem***.
The former "scenario builder" was designed with a concern for openness, that is to say make it possible to use different ***data pools***, from "ready-made" time-series to entirely "Antares-generated" time-series.
The figure below describes the general pattern that characterizes Antares simulations.



<u>Time-series analysis and generation</u>

When ready-made time-series are not available or too scarce (e.g. only a handful of wind power time-series) for carrying out proper MC simulations, the built-in Antares time-series generators aim at filling out the gap. The different kinds of physical phenomena to model call for as many generators:

a) The daily thermal fleet availability generator relies on the animation of a most classical three-state Markov chain for each plant (available, planned outage, forced outage)
b) The monthly hydro energies generator is based on the assumption that, at the monthly time scale, the energies generated in each area of the system can be approximated by Log Normal variables whose spatial correlations are about the same as those of the annual rainfalls.
c) The hourly wind power generator is based on a model [5] in which each area's generation, once detrended from diurnal and seasonal patterns, is approximated by a stationary stochastic process.

The different processes are eventually simulated with proper restitution of their expected correlations through time and space. The identification of the parameters that characterize at best the stochastic processes to simulate can be made outside Antares but this can also be achieved internally by a built-in historical time-series analyzer.

<u>Economy simulations</u>

When simulating the economic behaviour of the system in a "regular" scenario (in that sense that generation can meet all the demand), it is clear enough that the operating costs of the plants disseminated throughout the system bear heavily on the results of the competition to serve the load. As known, the most simple way to model the underlying market rationale is to assume that competition and information are both perfect, in which ideal case the system's equilibrium would be reached when the overall operating cost of the dispatched units is minimal.

Altogether different is the issue of the time-frame to use for the economic optimization: realism dictates that optimization should neither attempt to go much further than one week (letting aside the specific case of the management of hydro resources) nor be as short-sighted as a one-hour snapshot.

Put together, these assumptions lead, for economic simulations, to the formulation of a ***daily/weekly linear program***, whose solution could be found using the standard simplex algorithm.

Yet, since a very large number of weekly simulations are carried out in a row (52 for each MC year, several hundreds of MC years for a session) and considering the fact that many features of the problems to solve may be transposed from one week to the next (e.g. grid topology), it proved very efficient to implement in Antares a variant of the ***dual-simplex algorithm*** instead of the standard algorithm. For each area of the system, the main outcomes of economy simulations are the estimates at different time scales (hourly, daily, weekly, monthly, annual) and through different standpoints (expectation, standard deviations, extreme values) of the main economic variables:

a) Area-related variables: operating cost, marginal price, GHG emissions, power balance, power generated from each fleet, unsupplied energy, spilled energy.
b) Interconnection-related variables: power flow, congestion frequency, congestion rent (flow multiplied by the difference between upstream and downstream prices), congestion marginal value (CMV - decrease of the overall optimal operating cost brought by 1MW additional transmission capacity).

Grid modelling

The tool offers different features which, combined together, give a versatile framework for the representation of the grid behaviour.

a) Interconnectors (actual components or equivalent inter-regional corridors) may be given hourly transfer/transmission asymmetric capacities, defined with a one-hour time step.
b) Asymmetric hurdle costs (cost of transit for 1MW) may be defined for each interconnector, again with a one-hour time-step.

An arbitrary number of either equality, two-side bounded or one-side bounded linear constraints may be defined on a set of hourly power flows, daily energy flows or weekly energy flows. In parts of the system where no such constraints are defined, power is deemed to circulate freely (with respect to the capacities defined in (a)). In other parts, the resulting behaviour depends on the constraints definition. A typical choice consists in obtaining DC flows by using either PTDF-based or impedance-based hourly linear constraints. Note that the latter is a usually more efficient way to model the grid because it is much sparser than the former. Other constraints may be defined to serve quite different purposes, such as, for instance, the modelling of pumped-storage power plants operated on a daily or weekly cycle.

6.3.2 BID

BID3 is Pöyry Management Consulting's power market model, used to simulate the dispatch of all supply and demand in electricity markets. Equally capable of covering both short-term analyses for trading and long-term scenarios, BID3 is a fast, powerful and flexible tool that provides comprehensive price projections in an intuitive and user-friendly interface.
Pöyry has built a security of supply module in its fundamental power market model BID3

What is BID3?

BID3 is an economic dispatch model based around optimisation. It models the hourly generation of all power stations on the system, taking into account fuel prices and operational constraints such as the cost of starting a plant. It accurately models renewable sources of generation such as hydro, reflecting the option value of water, and intermittent sources of generation, such as wind and solar using detailed and consistent historical wind speed and solar radiation.

What is BID3 used for?

BID3 provides a simulation of all the major power market metrics on an hourly basis – electricity prices, dispatch of power plants and flows across interconnectors. BID3 can be run for both short term market forecasts and long term scenario analysis. BID3 is the perfect tool to assess the market value of power plants under a range of situations, through outputs like market revenue, load factor, fuel and CO2 costs, or the number of starts per year. These results can be computed for a single plant, or for an entire project portfolio for planning and investment purposes, assessing the effect of both internal decisions and a large range of external factors. BID3 can be used for the economic assessment of interconnectors, outlining flows and congestion rent, as well as socioeconomic and other commercial benefits. BID3 has a very detailed description of intermittent renewable sources, basing generation on historically observed wind speed and solar irradiation data.

BID3 combines state-of-the-art simulation of thermal-dominated markets, reservoir hydro dispatch under uncertainty, demand-side response and scenario-building tools.

Key features:

- Sophisticated hydro modelling, incorporating stochastic Dynamic Programming to calculate the option value of stored water.
- Detailed modelling of intermittent generation, such as wind and solar, allowing users to understand the impact of renewables and requirements for flexibility.
- Advanced treatment of commercial aspects, such as scarcity rent and bidding above short-run marginal cost.

Adequacy calculations

Security of Supply module is fundamentally different from a market simulation

- Market simulation: valued product is MWh; objective is to minimize cost of supply
- Security of supply: valued product is MW; objective is to maximize security of supply

Security of Supply can be seen in two steps, for each hour:

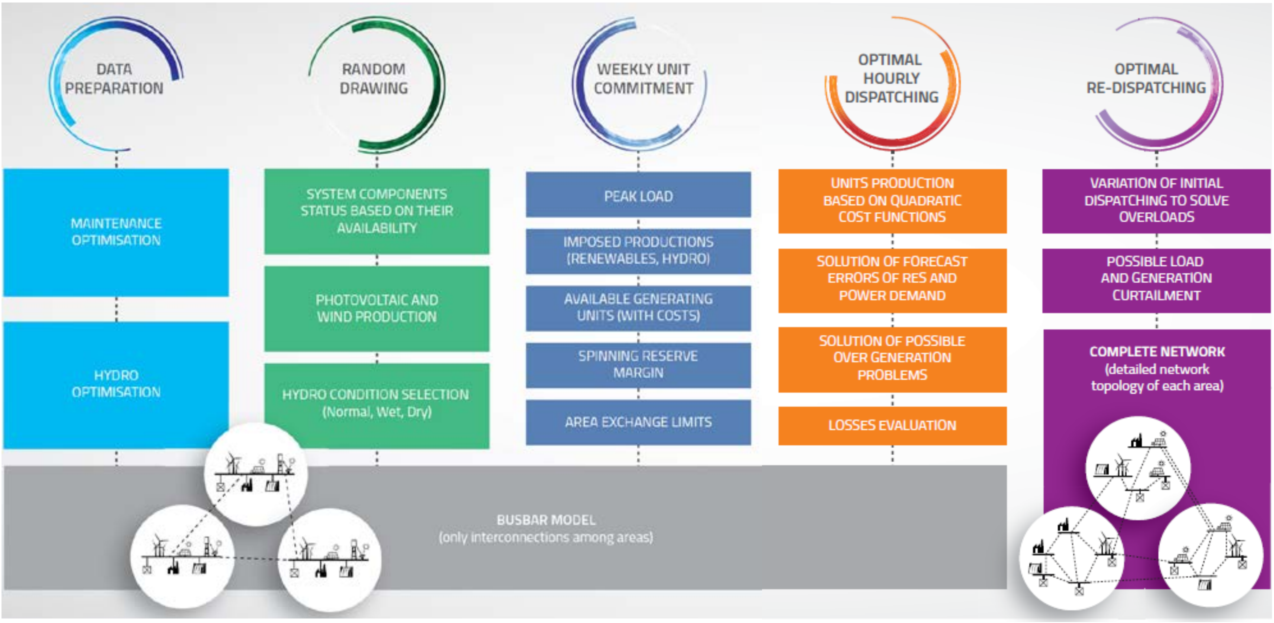
- local margin: available capacity in a price area minus demand for that price area
- regional margin: local margin, modified by the contribution of interconnectors

The capacity adequacy assessment module calculates both local and regional margin according to different scenarios, for all future years, over many stochastic or weather-based series.

6.3.3 GRARE

GRARE, Grid Reliability and Adequacy Risk Evaluator, is a powerful computer-based tool of Terna, developed by CESI[19], that evaluates reliability and economic operational capability using probabilistic Monte Carlo analysis.
GRARE has been developed to support medium and long-term planning studies and is particularly useful for evaluating the reliability of large power systems, modelling in detail the transmission networks.
The tool is developed taking advantage of a high performance multi-threaded code and it is integrated in SPIRA application, that is designed to perform steady-state analyses (e.g. load-flow, short-circuits, OPF, power quality) and is based on a network Data Base of the system being analysed.

The calculation process is performed as a series of sequential steps starting from a high-level system representation and drilling down to low-level network details. Thanks to the ability to couple the economic dispatch of the generation with the complete structure of the electrical network, GRARE is able to offer a unique support for the planning and evaluation of the benefits related to network investments.



The **complete network model** (lines, generators, transformers, etc.) includes different voltage level detail and the power flow derived from generation dispatching to feed the load is obtained applying a DC load flow with the possibility to obtain power losses and voltage profile estimation. Starting from a complete network model, GRARE is able to automatically obtain a simplified bus-bar models to complete unit commitment and market analyses where the network detail is not needed. The analysis of the full network model allow to verify the feasibility of the economic dispatching and the necessity to apply a re-dispatching or load shedding to operate the network in accordance to security criterion.

[19] www.cesi.it/grare

Algorithm and main optimization process

- The time horizon is a single year with a minimum time unit of one hour. Many Monte Carlo Years (MCYs) can be simulated, each one being split into 52 weeks with each week independently optimized.
- Probabilistic Monte Carlo method uses statistical sampling based on a “Sequential” or “Non Sequential” approach.
- Monte Carlo convergence analysis to verify the accuracy of results obtained.
- Optimized Maintenance schedule based on residual load distribution over the year.
- Reservoir and pumping Hydro optimization mindful of water value as an opportunity cost for water in respect to other generation sources.
- Different hydro conditions managed (dry, normal, wet).

System model

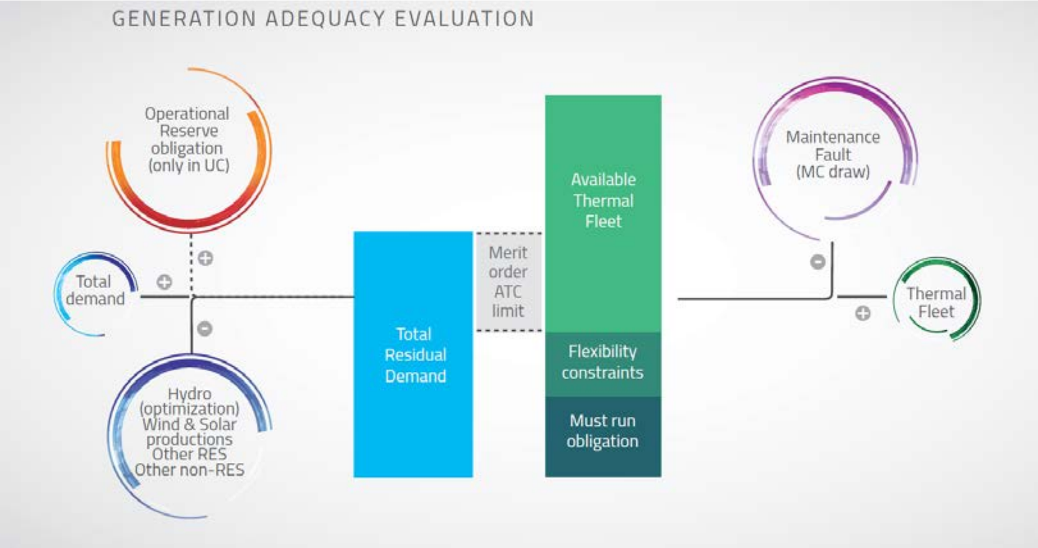
- Network detail to represent each single area (grid dimension up to 5,000 buses). A DC load flow is calculated and an estimate of voltage level can be obtained using the Sauer algorithm.
- Area modelling to optimize Unit commitment and Dispatching consistent with transfer capacities.
- Unit Commitment and Dispatching with Flow or ATC based approach.

Market analyses

- Single year day-ahead Market analysis with area modelling detail, but with no Monte Carlo drawings.
- The general restrictions of the Unit Commitment like minimal uptime and downtime of generation units are taken into account for each optimization period.
- Dispatchable units characterised by power limits, costs, must-run or dispatching priority, power plants configurations, start-up and shutdown flexibility and CO2 emissions.

Adequacy analyses

- System adequacy level measured with Reliability Indexes (EENS, LOLE, LOLP).
- Renewable production calculated by a random drawing starting from producibility figures.
- Operational reserve level evaluation taking account of largest generating unit, uncertainty of load and RES forecast, possible aggregation of Area and fixed % of load.
- Demand side management as rewarded load to be shed with priority without impact on adequacy.
- Over-generation management with possible priority on generation to be reduced.



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Main applications

The high level of versatility and flexibility of the GRARE tool has been appreciated in Europe first and then in several countries all around the world. The program has been developed to be applied in the design phase for the Italian framework and it is now used for ENTSOE-E adequacy studies. Various TSO/Institutions have benefited from the potentiality of the tool by using it directly or through specialist consultancy services.

- Designed for technical analyses of large electric systems.
- Evaluation of electric systems
- Generation & Transmission adequacy.
- Optimal level of RES integration.
- Cost Benefits Analysis for network reinforcements and storage which factors in Security of Supply, network overloads, RES integration, network losses, CO2 emissions and over-generation.
- Calculation of Total Transfer Capacity of interconnections.
- Generation reward evaluation for Capacity Remuneration Mechanism.
- Point Of Connection and sizing for new power plants.

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6.3.4 PLEXOS

PLEXOS, developed by Energy Exemplar, is a sophisticated power systems modelling tool. It uses mixed integer optimisation techniques to determine the least cost unit commitment and dispatch solution to meet demand, while respecting generator technical-economic constraints.
Advanced Mixed Integer Programming (MIP) is the core algorithm of the simulation and optimization.

PLEXOS 4.0 was first released in 2000. It is used by utilities, system operators, regulators and consulting firms for:

- Operations
- Planning and Risk
- Market Analysis
- Transmission (Network) Analysis

PLEXOS features:

- State-of-the-art optimisation-based engine using latest theories in mathematical modeling and game-theory
- Co-optimises thermal and hydro generation, transmission, and ancillary services given operational, fuel, and regulatory constraints
- Dispatch and pricing solutions are mathematically correct, robust and defensible
- Applies optimisation across multiple timeframes
- Benchmarked against real market outcomes and existing large-scale models

<u>Solving UC/ED using MIP</u>

Unit Commitment and Economic Dispatch can be formulated as a linear problem (after linearization) with integer variables representing generator on-line status.

Minimise Cost = *generator fuel and VOM cost + generator start cost*
+ contract purchase cost –contract sale saving
+ transmission wheeling
+ energy / AS / fuel / capacity market purchase cost
–energy / AS / fuel / capacity market sale revenue

Subject to

- Energy balance constraints
- Operation reserve constraints
- Generator and contract chronological constraints: ramp, min up/down, min capacity
- Generator and contract energy limits: hourly / daily / weekly / …
- Transmission limits
- Fuel limits: pipeline, daily / weekly/ …
- Emission limits: daily / weekly / …
- Others

<u>Hydro-Thermal planning</u>

Particularly important for the MAF studies was the co-ordination of Hydro-Thermal planning. The goal of the hydro-thermal planning tool is to minimize the expected thermal costs along the simulation period. PLEXOS Integrated Energy Model offers a seamless integration of phases, making it possible to determine:

- An optimal planning solution in the medium-term
- and then use the obtained results in a detailed short-term unit commitment and economic dispatch problem with increased granularity.
  Eg. weekly targets as constraints filter down to produce hourly electricity spot prices.

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